TRILOGY
ENERGY TRUST

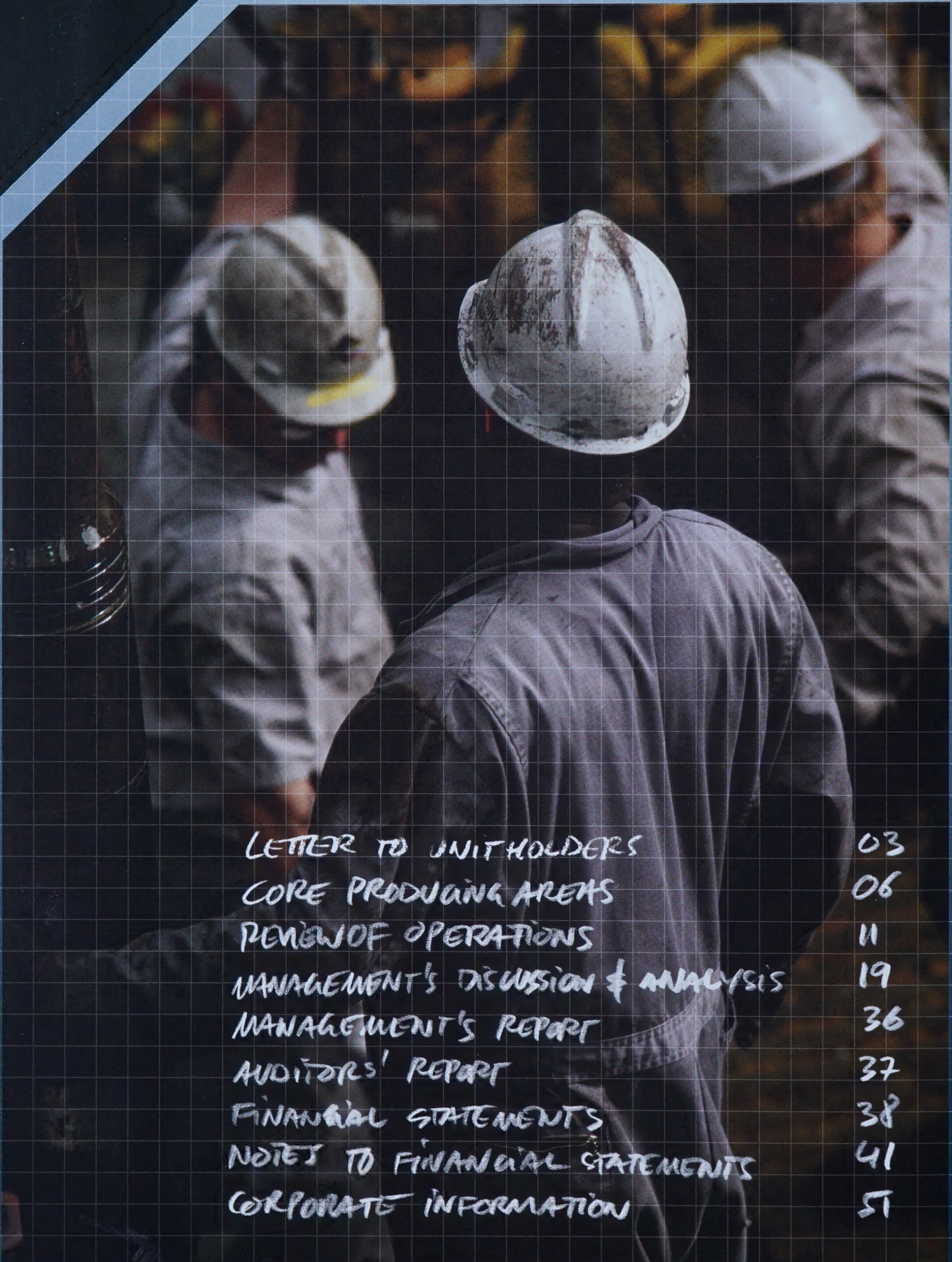
2005 ANNUAL REPORT

MD&A
Financial Statements
Review of Operations
Letter to Unitholders

WELL CONSTRUCTION LOG

LOCATION
123 Main Street

Black Sandstone, moderately hard, moderately strong, highly weathered (continued)



Financial and Operating Highlights

(thousands of dollars except per unit amounts and where stated otherwise)	Three Months Ended Dec. 31 2005	Three Months Ended Sept. 30 2005	Year Ended Dec. 31 2005[1]	Year Ended Dec. 31 2004[1]
FINANCIAL				
Petroleum and natural gas sales	**159,932**	131,052	**508,881**	327,611
Funds flow[2]				
From operations	**82,098**	68,170	**254,764**	166,502
Per unit - basic[3]	**1.04**	0.86	**3.22**	2.10
- diluted[3]	**1.04**	0.86	**3.22**	2.10
Earnings				
Earnings before certain items[6]	**53,513**	31,942	**118,790**	52,435
Net earnings (loss)	**87,675**	(2,529)	**86,447**	25,543
Per unit - basic[3]	**1.11**	(0.03)	**1.09**	0.32
- diluted[3]	**1.11**	(0.03)	**1.09**	0.32
Distributions declared	**107,674**	45,106	**190,763**	–
Per unit	**1.30**	0.57	**2.35**	–
Capital expenditures				
Exploration and development	**45,331**	25,820	**140,218**	101,628
Acquisitions, dispositions and other	**6,491**	150	**7,834**	172,414
Net capital expenditures	**51,822**	25,970	**148,052**	274,042
Total assets	**777,793**	761,587	**777,793**	778,147
Net debt[4]	**183,677**	280,450	**183,677**	10,249
Unitholders' equity	**462,365**	340,397	**462,365**	532,430
Trust Units outstanding (thousands)				
As at December 31, 2005 (September 30, 2005)	**85,133**	79,133	**85,133**	–
As at March 3, 2006	**85,133**	–	**85,133**	–
OPERATING				
Production				
Natural gas (MMcf/d)	**116**	116	**117**	98
Crude oil and liquids (Bbl/d)	**4,826**	5,154	**4,928**	3,880
Total production (Boe/d) @ 6:1	**24,109**	24,404	**24,495**	20,288
Average prices				
Natural gas (pre-financial instruments) ($/Mcf)	**12.05**	9.31	**9.23**	7.13
Natural gas ($/Mcf)[5]	**10.98**	9.09	**8.86**	7.22
Crude oil and liquids (pre-financial instruments) ($/Bbl)	**71.38**	67.72	**63.03**	49.89
Crude oil and liquids ($/Bbl)[5]	**69.20**	62.38	**61.57**	46.77
Drilling activity (gross)				
Gas	**18**	15	**66**	64
Oil	**3**	3	**8**	8
D&A	**–**	1	**5**	1
Total wells	**21**	19	**79**	73
Success rate	**100%**	95%	**94%**	99%

(1) The financial statements prior to April 1, 2005 were prepared on a carve-out basis from Paramount. These financial statements may not be indicative of the results that would have been attained if the Trust had operated as a stand-alone entity for these periods.

(2) Funds flow from operations is a non-GAAP term that represents net earnings adjusted for non-cash items and certain exploration costs. The Trust considers funds flow from operations a key measure as it demonstrates the Trust's ability to generate cash necessary to fund future growth through capital investment and to repay debt. Funds flow should not be considered an alternative to, or more meaningful than, net earnings as determined in accordance with Canadian GAAP.

(3) Per unit amounts were calculated for the periods between April 1, 2005 and December 31, 2005 using the weighted average number of units outstanding. For periods prior to April 1, 2005 the initial number of units outstanding was used.

(4) Net debt is equal to long-term debt plus/minus working capital.

(5) Excludes non-cash gains and losses on financial instruments.

(6) After excluding the impact of: unrealized gain (loss) on financial instruments and accrued unit-based compensation expense since April 1, 2005. In addition, earnings before April 1, 2005 have been adjusted for taxes, foreign exchange gains and losses, bad debt recovery, the premium on debt exchange and stock based compensation expense.


PROJECT: EAST KAYBOB
LOCATION - KAYBOB, AB
WELL / BORING #
MW-01
DRILLING EQUIPMENT: PRECISION DRILLING

Letter to Unitholders

Trilogy Energy Trust ("Trilogy") has completed its first fiscal year of operations and can proudly report its year-end results to Unitholders. Trilogy has quickly executed on its business plan starting on April 1, 2005, to transform itself into a stand-alone fully operational energy trust with an opportunity base second to none.

Trilogy was formed through the carve-out of select, high quality, high working interest assets in the Kaybob and Marten Creek areas of Alberta from Paramount Resources Ltd. These assets have exploitation opportunities on undeveloped acreage as well as the potential to further develop the lands that are already producing. The opportunity exists to drill hundreds of wells targeting tighter, natural gas charged reservoirs in the Kaybob area to capture reserves that would not otherwise be drained with the existing wells. These development opportunities provide Trilogy with the ability to maintain a stable production base, as well as replace the reserves that are produced annually, to maintain a stable reserve life index on a relatively low risk basis. The skill set and understanding of this Lower Cretaceous, tight gas development, have been developed over a decade, and the ultimate value of this asset base is only starting to be realized.

In 2005, we forecast production to average 25,000 Boe/d; our production for the year averaged 24,495 Boe/d. As we are planning and implementing our capital budget for 2006, we have maintained our goal of sustaining production at 25,000 Boe/d for the year. Through advanced planning we anticipate executing a development plan to reach our production goal for the year.

The past year has been a volatile year in the industry as increased commodity prices led to a dramatic increase in drilling activity resulting in a shortage of equipment and skilled labour, and higher prices for these services. As well, our activity was complicated even further by unseasonable weather throughout the year, starting first with record wet weather in the spring and summer and ending with a very mild winter hampering entry to areas that are accessed only in the winter months when the ground is frozen. These factors have challenged the entire industry to be more innovative in executing their strategies. Despite these challenges, Trilogy has been able to execute on its plan to replace reserves at attractive prices, replace production declines, and identify future development opportunities, in order to provide a stable monthly distribution into the foreseeable future.

Commodity prices rose throughout the year, allowing all energy trusts to make their revenue targets and maintain distributions. Trilogy is of the opinion that commodity prices should remain strong over the long term. We raised the monthly distribution in September of 2005 from $0.16/unit to $0.25/unit reflecting these higher prices. These high commodity prices also allowed us to grant our Unitholders a special distribution in December of an additional $0.55/unit. The special distribution was required as a means of distributing surplus cash flow resulting from strong production performance coupled with exceptional commodity prices. This special distribution relieved any potential that the trust would have any current taxes payable in 2005.

Trilogy's capital program provided industry leading finding and development costs of $10.74/Boe which when compared to Trilogy's fourth quarter 2005 netback of $45.02/Boe implies a recycle ratio of 4.2. Put more simply, for every dollar Trilogy invested in its asset base, it returned $4.20 of value to the Unitholders. The capital program for 2005 totaled $148 million which included costs associated with drilling, completions, facility construction, as well as land purchases, minor acquisitions and some costs on projects that were carried forward from prior periods. The majority of the capital was spent on drilling and completion operations, as the strategy for the Trust has been to organically replace production and reserves through drilling and completing our internally generated prospects. The majority of the prospects to be drilled in 2006 will be targeting lower risk development opportunities with the continued mandate of maintaining a solid production base and replacing produced reserves, similar to the 2005 program. There will also be a small capital component in the 2006 drilling program that will target pool extensions and new pools discoveries. As we replace our reserves

and maintain our production base we can expect our reserve life index to remain at approximately seven to eight years for proved plus probable reserves which Trilogy believes will provide optimal returns to the Unitholders. This will allow us to continue paying out a significant portion of our cash flow out to Unitholders in the form of monthly distributions.

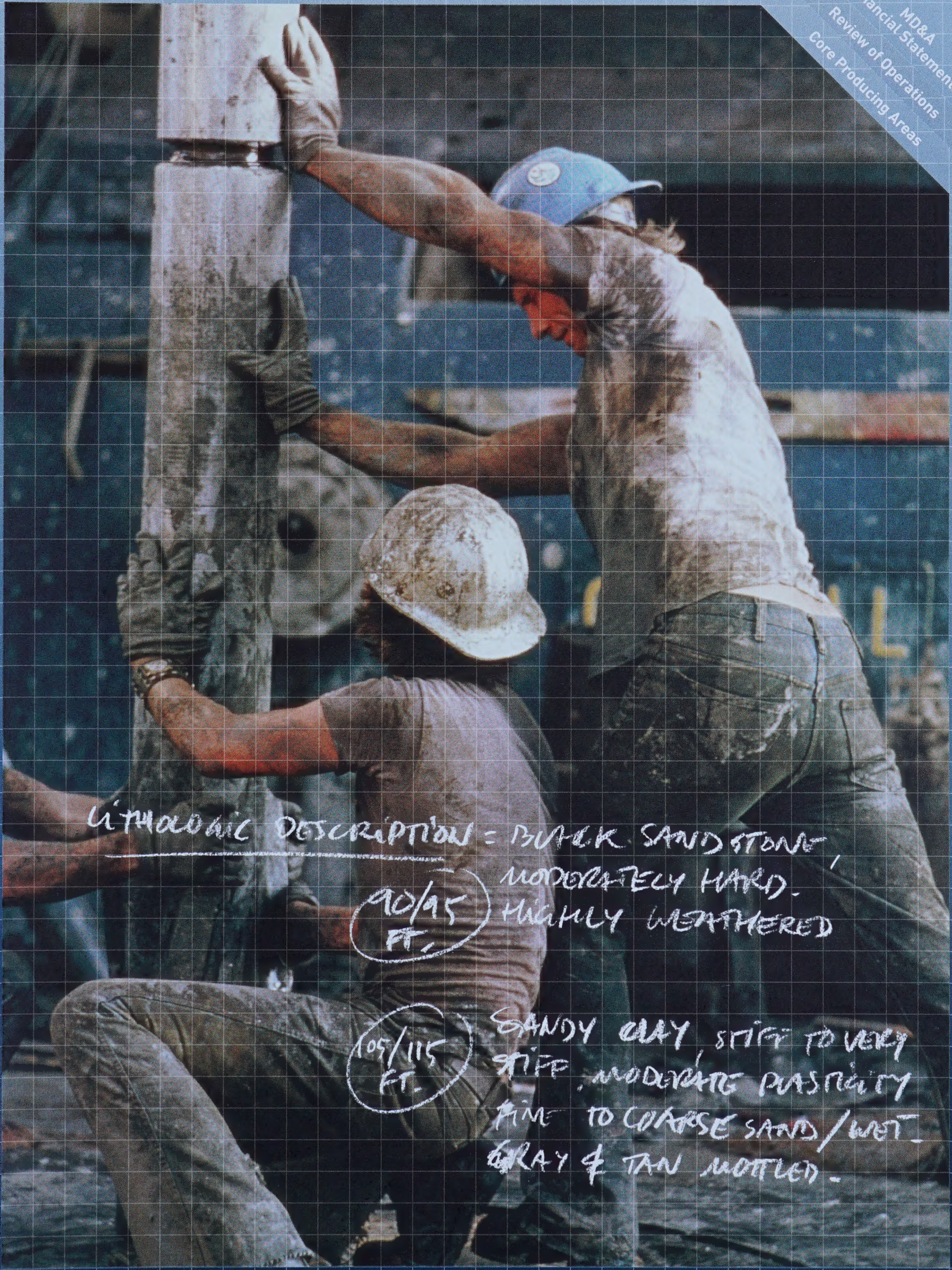
Trilogy has developed its strategy around exploiting its asset base as well as evaluating strategic acquisitions. Acquisition metrics in 2005 remained high and as a result, we were not successful in acquiring any new material assets in 2005. We did acquire a small asset in the Kaybob area for $6.5 million which included 80 Boe/d plus additional royalty income, as well as some development drilling opportunities. In 2006, we will continue to evaluate acquisition opportunities where we are able to leverage our technical expertise and if successful, the acquisition metrics will be accretive to our Unitholders.

In December 2005, Trilogy entered into a bought deal financing whereby we issued six million trust units for net proceeds of $140.6 million. These funds were used to repay the credit facility and augment operating fund requirements. Maintaining a clean balance sheet with significant unused debt capacity will allow us the flexibility to continue to pursue acquisitions and allow the Trust to execute its business plan through fluctuating commodity price cycles.

Subsequent to the year end, Trilogy entered into an arrangement agreement with Redsky Energy Ltd., a private Alberta oil and gas company, providing for the acquisition of all of the issued and outstanding common Redsky Shares for aggregate consideration of 6,500,000 Trilogy units. Trilogy believes the acquisition of Redsky represents an excellent opportunity to add value and sustainability for our Unitholders. The transaction is expected to be immediately accretive to cash flow per unit and offers competitive transaction metrics of $51,300 per flowing Boe/d, and $20.54 per Boe of proved plus probable reserves. Trilogy's strategy to grow through the exploitation of tight gas resources in the Kaybob area can be employed in a similar exploitation strategy on the Redsky assets and the undeveloped land base will provide Trilogy with additional lower risk exploitation drilling opportunities. Redsky's current production is approximately 2,300 Boe/d, over 80 percent of which is natural gas. This production volume should increase as Redsky has a number of high quality drilling commitments that are expected to be completed prior to breakup, and should generate additional value for Trilogy Unitholders.

Our first year was exciting and challenging. We were exposed to large swings in commodity prices and extreme weather conditions. Trilogy has positioned itself as a strong performing natural gas focused energy trust with a tremendous asset base and high quality staff. We continue to focus our strategy on replacing produced reserves and providing a stable production profile. We will continue to be prudent in our investment decisions, and manage our spending so that we can provide our Unitholders with high capital efficiencies metrics on the exceptional asset base that we have assembled. We have managed our risk by entering into hedging positions that will provide some stability to our cash flow and allow us to maintain our distributions and capital spending program. We will continue to maintain a corporate culture that supports safety, creativity, innovation and teamwork, in order to provide our Unitholders with high quality investment.

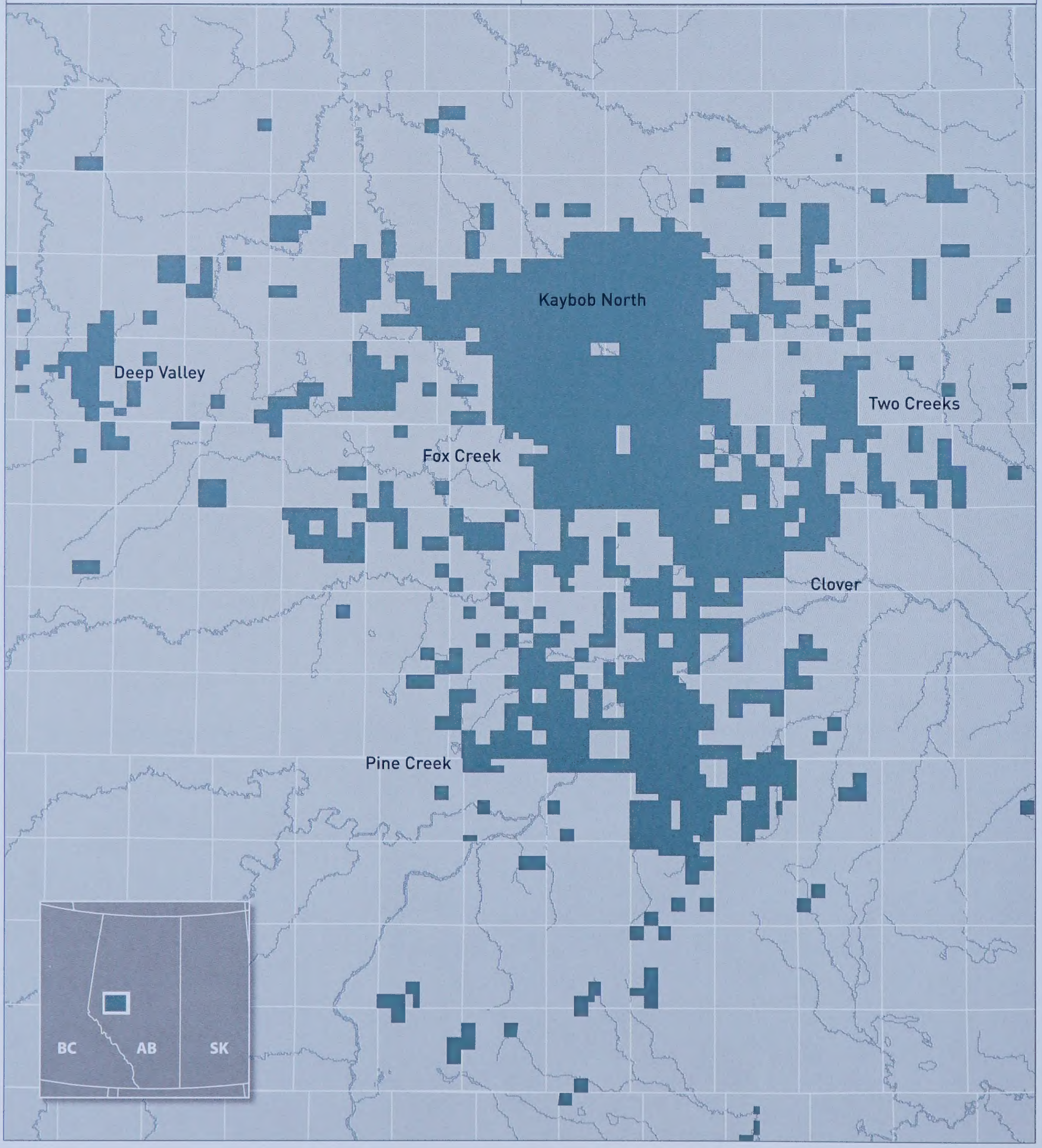
Jim Riddell
President & Chief Executive Officer


LITHOLOGIC DESCRIPTION = BLACK SANDSTONE, MODERATELY HARD. HIGHLY WEATHERED
90/95 FT.
105/115 FT.
SANDY CLAY, STIFF TO VERY STIFF. MODERATE PLASTICITY FINE TO COARSE SAND/WET. GRAY & TAN MOTTLED.

Core Producing Areas

Kaybob

Estimated 2006 Production	21,667 Boe/d	Developed Land	272,411 acres (gross)
Proved Reserves	41,931 MBoe	Drill Depth	2,200 m
Proved Plus Probable Reserves	61,102 MBoe	Operating Costs	$7.93/Boe
Undeveloped Land	440,119 acres (gross)	Estimated 2006 Capital Budget	$110 MM



Kaybob Area

Our staff have been active in the Kaybob area, first with Paramount, and now with Trilogy, for the past 14 years. We believed this area to be an extremely resource rich area of the province that still offered a large number of exploitation opportunities. This area contains significant accumulations of crude oil and natural gas from the Devonian Swan Hills formation, that are buried up to 3,600 meters deep, to the Belly River formations at average depths of 600 meters. Trilogy has developed the technical experience in the office and in the field to exploit these formations and create significant value.

Trilogy currently has a production portfolio that contains a mix of conventional crude oil and natural gas production and unconventional gas production from tight gas reservoirs. The following chart highlights our estimated 2006 natural gas and crude oil and natural gas liquids production by formation.

Producing formation	Natural Gas MMcf/d	Crude Oil and NGL Bbl/d	Boe/d
Viking, Notikewin and Shallower	43	879	8,046
Bluesky, Gething, Cadomin	44	1,172	8,505
Nordegg, Montney	3	375	875
Swan Hills	10	2,574	4,241
Total Production	100	5,000	21,667

Trilogy has developed a strategy built around the exploitation of tight gas reservoirs in the Kaybob area. The primary zones of interest at this time are the Bluesky, Gething and Cadomin formations of the Lower Mannville. These reservoirs are generally fine grained sands that were deposited in marine or fluvial environment which has resulted in a complex reservoir development. These reservoirs cannot be fully exploited with one producing gas well per section and the industry has requested and been granted approval from the Alberta Energy and Utilities Board to drill and produce from more than one well per section. In some cases, companies have drilled up to four wells per section to capture all of the natural gas resource in place.

Our strategy will be to manage the down-spacing program by drilling two wells per section, evaluate the results, move to three and then four wells per section if required to economically recover all of the producible resource.

In the Kaybob area in 2005 we drilled 65 (51.3 net) wells, 60 percent of these wells targeting the down-spacing opportunities in the Gething formation. As we exploit the Gething reservoirs we gather information on the other tight gas reservoirs in the area that will ultimately be down-spaced with the same strategy we currently employ with the Lower Mannville reservoirs.

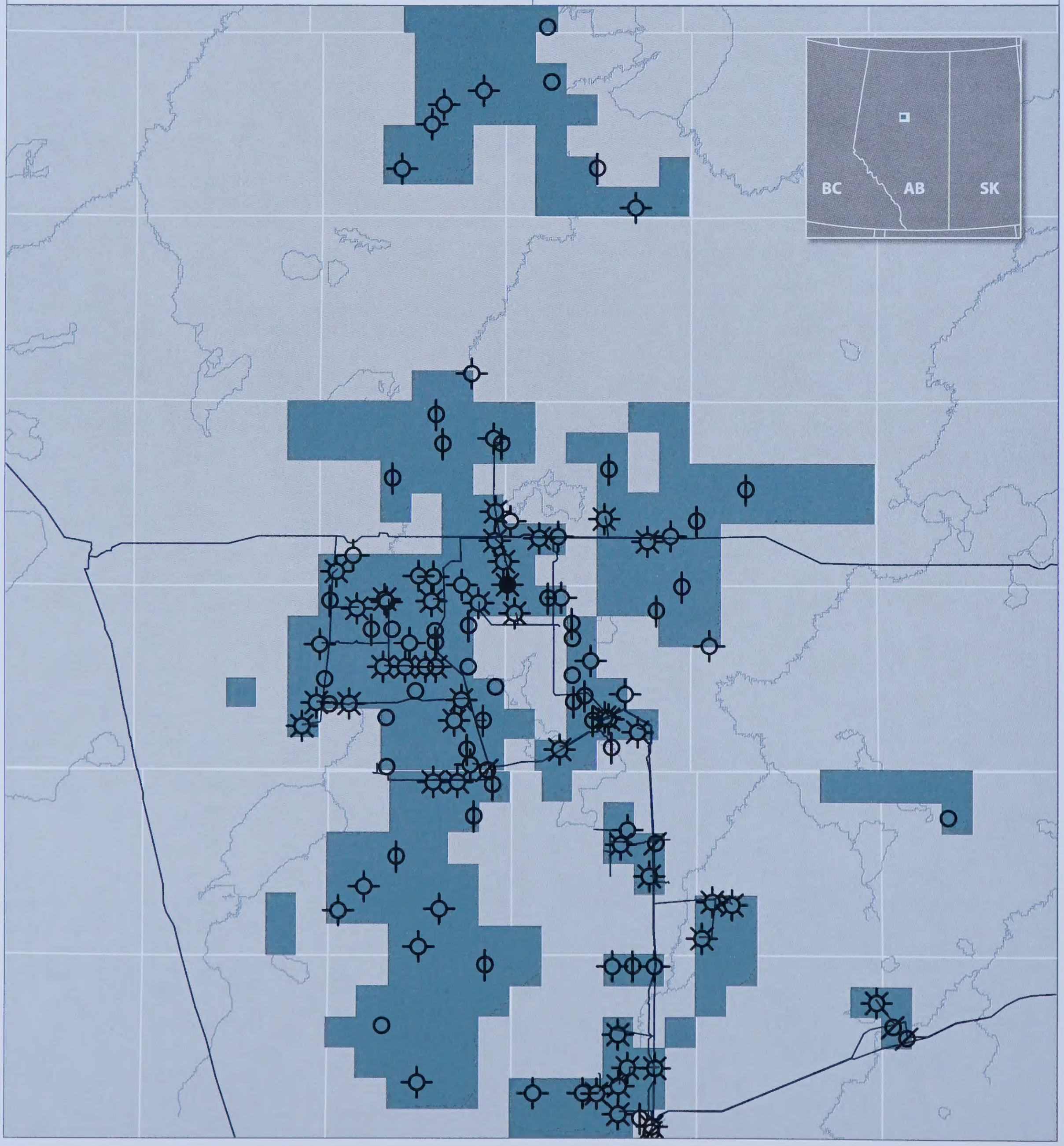
In 2006 we anticipate spending $110 million of our $120 million capital budget in Kaybob where the drilling activity will be at a similar level to 2005 and the focus will remain on the exploitation of the tight gas in the Lower Mannville reservoirs. We have developed our drilling and completion techniques to optimize the production and reserve potential of each well and ultimately maximize the return on capital for each well drilled. By combining natural gas production from different formations, referred to as commingling production, we are able to reduce our costs to complete and tie in the wells. We have been actively evaluating alternatives to commingle production from the tight gas and conventional reservoirs, as well as natural gas from sweet and sour reservoirs, in an attempt to keep capital costs down thereby reducing finding and development costs.

In 2005 we were challenged by the early breakup in March, an extremely wet summer and warmer than expected winter. Our experience in this area allows us to be innovative and flexible when these challenges arise so that we can execute our business plans and minimize disruptions. We are in a position that we can deal with most operational issues in a timely fashion to reduce the impact on production and costs.

We are constructing our fourth operated gas plant in the Waskahigan area at what will be referred to as the Deep Valley property. Trilogy believes that if we have control of our plants and gathering systems we can maintain better control of our production, operating costs and ultimately, our cash flow.

Marten Creek

Estimated 2006 Natural Gas Production	20 MMcf/d	Drill Depth	500 m
Proved Reserves	3,234 MBoe	Description	Shallow Gas Sands
Proved Plus Probable Reserves	4,381 MBoe	Working Interest (Natural gas)	100%
Undeveloped Land	125,440 acres (gross)	Operating Costs	$5.67/Boe
Developed Land	20,480 acres (gross)	Estimated 2006 Capital Budget	$10 MM



Marten Creek Area

The Marten Creek property is located approximately 150 kilometers northeast of the Kaybob properties. This property is in a winter-access area, which means access for vehicle traffic is restricted to late December until the end of March; helicopters are required to access the well sites during the remainder of the year. Off-road travel is restricted and requires the construction of ice roads to move any large trucks or equipment. We are required to have drilling, completion and construction programs prepared and approved well in advance of the winter season in order to execute our planned activity. As a result of the limited access, major operational problems must also be dealt with during the winter months.

The reservoir sands are typically at depths of less than 600 meters in this area, and are commonly referred to as shallow gas sands. The reservoirs can be relatively large in extent, covering five to ten square miles, or as small as half a section in size. Reservoir sands are typically very porous and permeable and a well may drain more than one section of reserves. We are targeting Viking, Grand Rapids, Clearwarter and Wabiskaw sands with our drilling programs. Companies have been actively exploring for these formations for a number of years, however with the benefit of higher natural gas prices we are able to target thinner sands that were previously overlooked.

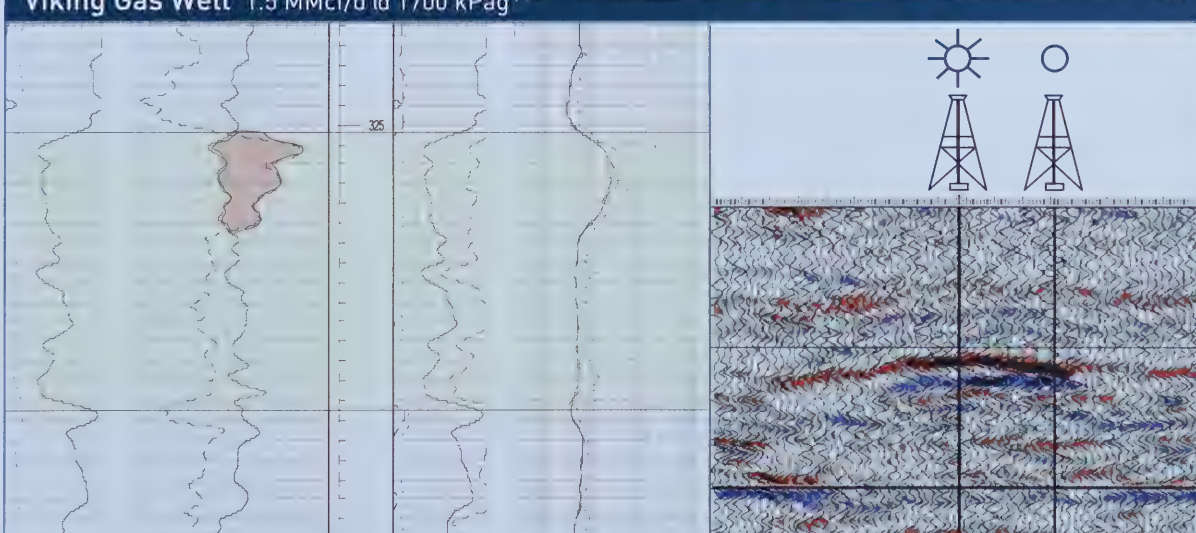
Shallow gas-filled reservoirs create a unique seismic signature known as a "bright spot". This is due to the gas-filled reservoir sands having a higher amplitude seismic response relative to reservoir rock that may be filled with water. This unique character allows us to identify gas versus wet reservoirs and makes seismic interpretation a critical tool for identifying high-quality drilling prospects in this area.

In 2005 we spent $19 million drilling 14 wells (100 percent working interest) and adding two field compressors to support the new gas that was discovered. In 2006 we will spend approximately $10 million to drill a similar number of wells; development capital costs are expected to be lower as we will not be required to install additional field compression for new gas reserves. We will also be shooting a seismic program to help identify additional drilling opportunities for our 2007 winter drilling program in this area.

Finding and development costs for shallow gas can be excellent. A typical shallow gas well can be drilled, completed for a single zone and tied in for $600,000 and have reserve potential of 0.3 to 3 Bcf. This will result in finding and development costs between $1.20 /Boe to $12.00 /Boe, which are very attractive metrics.

Trilogy's gas in this area is processed through a third-party gas processing plant. This facility is capable of handling 41 MMcf/d of natural gas and Trilogy has firm processing and transportation capacity for 26 MMcf/d, and we have targeted annual production to be 20 MMcf/d for this property. Each winter Trilogy will drill enough wells to meet our production commitment at the plant and have enough production capacity to replace production declines through the summer.

Viking Gas Well 1.5 MMcf/d @ 1700 kPag




DATE : JANUARY 10/06
SPUD DATE : JANUARY 18/06
TD EST. : 2,045 METRES
FLOWRATE : 2.5 MMCF/D

Review of Operations

Production

Production in Trilogy's core operating areas has grown steadily over the past three years. Average daily production in 2005 increased 21 percent from 20,288 Boe/d in 2004 to 24,495 Boe/d. **Trilogy believes that this asset base will maintain a stable production profile of around 25,000 Boe/d and as such our 2006 production forecast for these assets will remain unchanged at 25,000 Boe/d.** We expect that our existing gathering systems, field compression and processing facilities will support our production at this level without a significant amount of capital input in such facilities.

Our experience is that we can manage our business better if we control our production. We currently operate three gas plants and three oil facilities that process approximately 65 percent of our average daily production. Our operated facilities have consistently performed at a high level. Production from these properties has been relatively stable, declines are more predictable and there is less downtime from the facilities. We are currently in the process of constructing a new gas plant at Deep Valley, which is expected to come onstream in March 2006. This plant will initially be capable of producing 10 MMcf/d and has the ability to expand to 25 MMcf/d with the installation of additional compression and refrigeration.

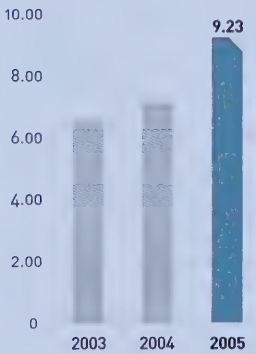
The following table summarizes the average daily production by core area for the past three years.

(on a carve-out basis)	2005	2004	2003
Natural Gas Production (MMcf/d)			
Kaybob	97.3	89.7	77.6
Marten Creek	20.1	8.6	0
Total	117.4	98.4	77.6
Crude Oil & NGL Production (Bbl/d)			
Kaybob	4,928	3,880	2,184
Marten Creek	0	0	0
Total	4,928	3,880	2,184
Total Production (Boe/d)			
Kaybob	21,144	18,856	15,112
Marten Creek	3,351	1,432	0
Total	24,495	20,288	15,112

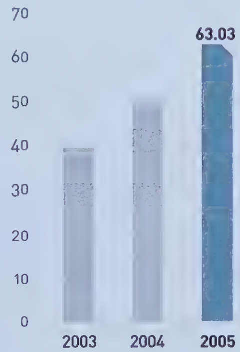
Commodity Prices

The average natural gas price before transportation and financial instruments increased 29 percent in 2005 to $9.23/Mcf from $7.13/Mcf in 2004. Trilogy is gas focused and in 2005 approximately 78 percent of revenue was derived from natural gas sales with an additional 9 percent from the sale of natural gas liquids. The Trust was well positioned to benefit from the increases in natural gas prices experienced in 2005. **Trilogy receives a premium natural gas price due to the high heat content of the gas produced from the Kaybob area.**

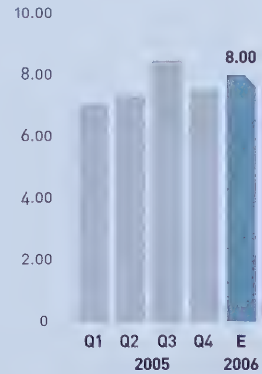
Natural Gas Price
($/Mcf, before financial instruments & transportation)



Oil & Natural Gas Liquids Price
($/Bbl, before financial instruments & transportation)



Operating Costs
($/Boe)



The average crude oil and natural gas liquid price before transportation and financial instruments increased 26 percent in 2005 to $63.03/Bbl from $49.89/Bbl in 2004.

To protect cash flows against commodity price volatility the Trust utilizes, from time to time, forward commodity price contracts that require financial settlement between counterparties. The financial instruments program is generally for periods of less than one year and would not exceed 50 percent of Trilogy's current production volumes. Refer to the Management's Discussion and Analysis for details on Trilogy's current financial instruments.

Operating Costs

Trilogy's activities and focus may change from quarter to quarter as a function of the access to certain properties and accordingly, operating costs can vary from quarter to quarter. In the winter months we concentrate on maintenance and workovers in areas that are not accessible during the summer months. This may include compressor maintenance, installation of well site facilities, pump changes and service rig work.

The winter-access Marten Creek area's operating costs are expected to be higher in the winter months when all of the budgeted operational activity takes place. As well, we may increase operational activity to maintain production when our capital activity is delayed. This was the case in the third quarter of 2005 when it was too wet to build pipelines to tie in new wells in the Kaybob area and extra workover costs were incurred on the existing wells.

The average operating cost for 2005 was $7.62/Boe. This was higher than anticipated as a result of increases in the costs of services. Higher commodity prices in 2005 increased all activities in the industry creating shortages of equipment and premium costs for guaranteed availability. **We are forecasting operating costs to be in a range of $7.50 to $8.00 per Boe in 2006.**

Operating costs for the Trust will increase with time, reflecting additional costs associated with producing natural gas from lower pressure reservoirs. As a general rule we will direct as much of our natural gas volumes through our operated facilities in order to monitor and manage these operating costs.

Net Capital Expenditures

Our 2005 capital expenditures, excluding land and acquisitions, were forecast to be approximately $100 million for the full year. The increase from this estimate to the amount reported was caused partly by expenditures on land and acquisitions, partly by expenditures on 2004 projects that were carried over to 2005 and on the general increase in costs. In addition, during the fourth quarter, Trilogy was able to accelerate work on some projects in order to make sure we had access to equipment in 2006. The additional capital expenditures incurred generated reserve additions and Trilogy is reporting favourable unit cost reserve additions as outlined in the summary of finding and development costs. **For 2006, Trilogy is budgeting $120 million, excluding land and acquisitions, for capital expenditures on the current asset base.**

Capital Expenditures (thousands of dollars)	**2005**
Land	10,564
Geological and geophysical	3,145
Drilling	96,718
Production equipment and facilities	29,791
Exploration and development expenditures	140,218
Property acquisitions	6,544
Proceeds received on property dispositions	(193)
Other	1,483
Net capital expenditures	148,052

Land

Trilogy spent $10.6 million at Crown land sales in 2005 to acquire 37,738 net acres bringing the total 2005 acreage to 685,425 net acres, of which 70 percent (477,940 acres) is considered undeveloped. This high average working interest land inventory will provide Trilogy with high quality drilling prospects that will be required to maintain its production. Trilogy will continue to farm in on third-party acreage as a means to earn an interest in prospective acreage, as well we will continue to farm out our expiring undeveloped lands that we do not consider prospective or consider to be outside of our risk tolerance. Trilogy will continue to add to its developed and undeveloped land base through 2006 to support our efforts to have a large inventory of drilling prospects for the future.

The Kaybob area has become highly competitive in the last few years. With higher commodity prices and successful drilling, the cost of undeveloped lands at Crown land sales has seen dramatic increases.

Our undeveloped land base provides us with a valuable asset in this highly competitive environment.

	2005		
Land (acres)	**Gross**	**Net**	**Average Working Interest**
Land assigned reserves	292,891	207,485	70.8%
Undeveloped land	565,559	477,940	84.5%
Total	858,450	685,425	79.8%
Fair market value of undeveloped land		$78,957,451	

Drilling

In 2005, including wells drilled prior to the April 1 spinout, Trilogy participated in 79 (65.4 net) wells, with an overall success rate of 94 percent (96 percent net). This high success rate reflects a drilling strategy that focuses on development and outpost wells in areas that have relatively low risk and multi-zone potential. Wells drilled in the first quarter accounted for 33 (28.4 net) wells of the total, 14 (14.0 net) of these wells being in the Marten Creek area and the balance in Kaybob. During the remainder of the year, Trilogy drilled 46 (37.0 net) wells, all of which were in the Kaybob area. **The multi-zone potential will provide us the opportunity to reduce the risk of a dry hole as well as allow for the exploration of new pools in the uphole formations.**

Over 75 percent of our drilling in the Kaybob area targets the Cadomin and shallower formations. Drilling in the Marten Creek area targets the zones from the Wabiskaw up to the Viking. In 2006 we expect our drilling activity to remain at the same level as in 2005.

	2005			
	Development		**Exploration**	
Drilling Results	**Gross**	**Net**	**Gross**	**Net**
Gas	49	42.94	17	14.80
Oil	8	5.25	0	0
D&A	2	0.45	3	2.00
Total All Wells	59	48.64	20	16.80
Success (%)	97	99	85	88

Reserves

Trilogy's reserves evaluation for the year ended December 31, 2005 has been prepared by Paddock Lindstrom and Associates. The report has been prepared in accordance with the National Instrument 51-101 definitions, standards and procedures. Natural gas reserves for the year ended 2005 were 314 Bcf compared to 306 Bcf for the year ended 2004. For the same period of time, crude oil reserves decreased from 6,085 MBbl to 5,647 MBbl, while natural gas liquids increased

from 7,222 MBbl to 7,510 MBbl. Proved plus probable reserves increased in total from 64,254 MBoe at December 31, 2004 to 65,494 MBoe at December 31, 2005.

The following table summarizes the gross (before royalties) reserves for the year ended December 31, 2005 using forecast prices and cost.

Reserve Category	Natural Gas Bcf	Crude Oil MBbl	Natural Gas Liquid MBbl	Boe (6:1) MBoe	Before tax Net Present Value ($millions)[1] 0%	5%	10%
Proved							
Developed Producing	183.0	3,633	4,738	38,870	1,252.8	1,038.7	901.2
Developed Non-Producing	23.1	118	300	4,270	129.2	109.2	95.2
Undeveloped	10.9	0	210	2,028	58.7	35.0	23.6
Total Proved	217.0	3,751	5,248	45,167	1,440.6	1,182.9	1,019.9
Probable	97.0	1,897	2,263	20,327	590.6	378.4	274.2
Total Proved plus Probable	**314.0**	**5,647**	**7,510**	**65,494**	**2,031.2**	**1,561.3**	**1,294.2**

Columns and rows may not add due to rounding.

(1) Including ARTC
The net present value of future net revenue after income taxes has not been included because the Trust is not taxable.

i) Reserve values were determined by Paddock Lindstrom ("Paddock") as at December 31, 2005, using the forward pricing assumptions in effect by the firm at that date.

ii) No value has been assigned to tangible assets other than those associated with proved producing reserves.

iii) Trilogy's financial instruments, which extend past December 31, 2005, have not been valued by Paddock Lindstrom.

iv) Reserve values have been evaluated under a blow-down scenario.

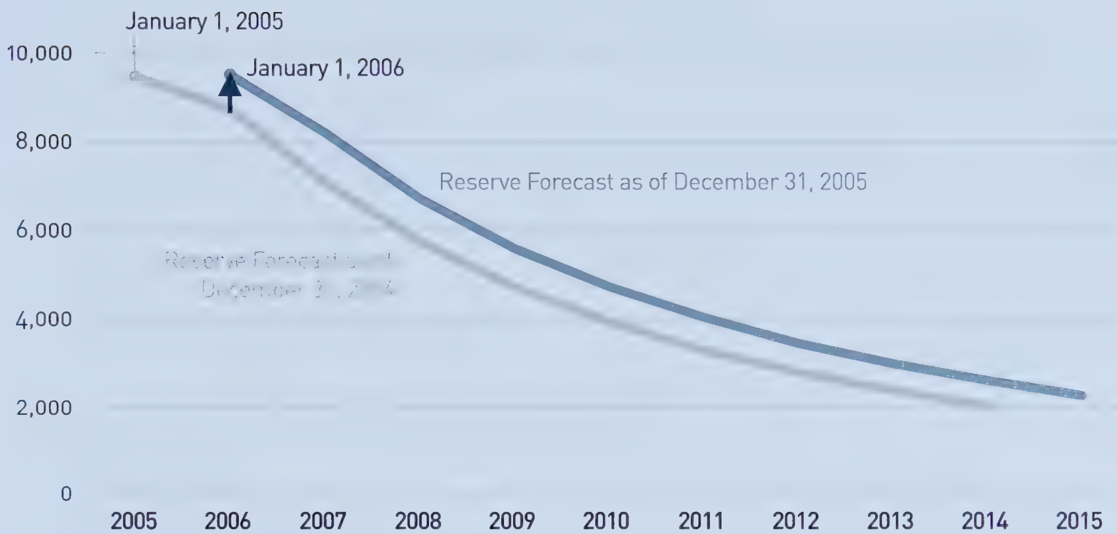
RESERVE RECONCILIATION FOR YEAR-END 2005

On a barrel of oil equivalent basis at 6 Mcf:1 Bbl, total proved reserves increased from 44,722 MBoe as of December 31, 2004 to 45,167 MBoe as of December 31, 2005. The following table sets forth the reconciliation of Trilogy's gross reserves for the year ended December 31, 2005 using forecast prices and costs:

	Total Proved Reserves				Probable Reserves				Total P+P Reserves			
	Natural Gas Bcf	Crude Oil MBbl	Natural Gas Liquid MBbl	Oil Equiv MBoe	Natural Gas Bcf	Crude Oil MBbl	Natural Gas Liquid MBbl	Oil Equiv MBoe	Natural Gas Bcf	Crude Oil MBbl	Natural Gas Liquid MBbl	Oil Equiv MBoe
At Dec 31, 2004	210.4	4,339	5,320	44,722	95.3	1,746	1,902	19,532	305.7	6,085	7,222	64,254
Total 2005 Acquisitions	1.0	0.0	15	176	0.4	-	5	71	1.4	0.0	20	247
Total 2005 Divestments	0.0	0.0	0.0	0.0	0.0	-	0.0	0.0	0.0	0.0	0.0	0.0
Extensions and Discoveries	31.1	149	485	5,945	6.5	49	207	1,338	37.5	197	692	7,283
Production for 2005	(42.1)	(888)	(899)	(8,936)	0.0	0.0	0.0	0.0	(42.1)	(888)	(899)	(8,936)
Technical Revisions	16.7	151	327	3,260	(5.2)	102	149	(614)	11.5	253	475	2,646
At Dec 31, 2005	217.0	3,751	5,248	45,167	97.0	1,897	2,263	20,327	314.0	5,647	7,510	65,494

Columns and rows may not add due to rounding.

Proved Plus Probable Reserve Forecast
(MBoe/year)



Trilogy replaced (excluding acquisitions) 2005 production by 103 percent on a proved reserve basis and 111 percent on a proved plus probable basis, thereby meeting one of our primary goals of replacing produced reserves.

By replacing produced reserves on a proved and on a proved plus probable basis, Trilogy has maintained a constant reserve life index.

FINDING AND DEVELOPMENT COSTS

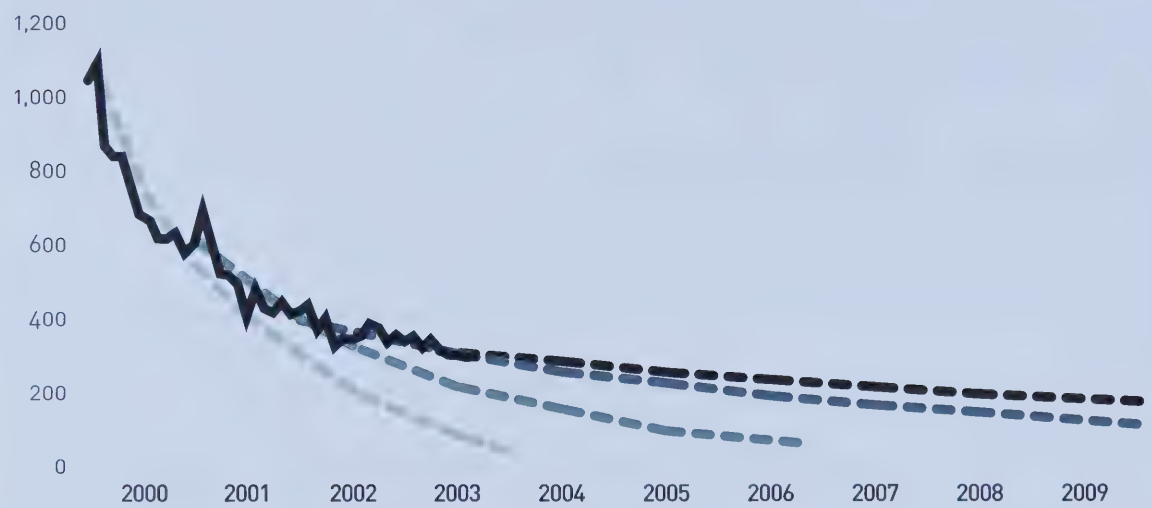
2005 Working Interest Capital Expenditures (millions of dollars)	**Capital**	**Change in Future Capital New Additions** Proved	P+P	**Total F&D Capital** Proved	P+P
Land	10.6			10.6	10.6
Geological and geophysical	3.1			3.1	3.1
Drilling	96.7	(3.7)	(23.2)	93.0	73.5
Production equipment and facilities	29.8			29.8	29.8
Land increase in value of undeveloped land	(10.4)			(10.4)	(10.4)
Total net capital expenditures	129.8	(3.7)	(23.2)	126.1	106.6

Trilogy spent $6.5 million for an acquisition of production, royalty income and undeveloped land in the Kaybob area that has not been included in the finding and development cost calculations.

Trilogy's finding and development costs for new reserve additions were calculated to be $13.70/Boe for proved reserves and $10.74/Boe for proved plus probable reserves.

	Proved Capital $MM	**Proved Reserves** MBoe	**Proved F&D** $/Boe	**Proved plus Probable Capital** $MM	**Proved plus Probable Reserves** MBoe	**Proved plus Probable F&D** $/Boe
F&D Cost						
Extensions, discoveries and revisions	$126.1	9,205	$13.70	$106.6	9,929	$10.74

Gething Production Profile
(Mcf/d)



The production profile of tight gas reservoirs such as the Gething formation typically produce with a high initial decline rate that decreases over time. As such, Trilogy expects to have positive technical reserve revisions each year for the Kaybob assets. Finding and development costs should remain low as we continue to exploit the multiple tight gas reservoirs in the Kaybob area. The graph above illustrates the production decline for a hypothetical Gething well, that was created from 106 single zone Gething gas wells drilled form 2000 to 2004. Initial declines are very steep and only limited reserves are assigned by the independent engineering company. Each additional year of production provides new information that allows for the ultimate recoverable reserves to be increased in each of the first four years that a well is on production based on a lower rate of decline; resulting in year over year positive reserve revisions for wells in tight gas reservoirs.

Subsequent Event

On February 28, 2006, Trilogy entered into an agreement with Redsky Energy Ltd. (Redsky) providing for the acquisition of all of the shares of Redsky for consideration of 6,500,000 Trilogy Energy Trust Units pursuant to a plan of arrangement. Trilogy is expected to assume negligible net debt as a result of this transaction.

The completion of the Plan of Arrangement is subject to various conditions, including receipt of all required regulatory, shareholder and court approvals. A special meeting of shareholders of Redsky is scheduled to be called on March 31, 2006.

Corporate Governance

The Board of Directors of Trilogy Energy Ltd., the administrator of Trilogy Energy Trust, are responsible for overseeing the governance of Trilogy. Trilogy has adopted sound principles of corporate governance so as to align the interests of its Board members and senior executive team with those of its investors. The Board has established written charters, codes and policies that clearly define the role of the Board and Trilogy's senior management as stewards of the Trust.

The Board of Directors is comprised of seven members, five of whom are independent. The Board operates under a written Mandate, which provides direction on the authority of the Board and its duties and responsibilities with respect to supervising the management of the business and affairs of Trilogy.

There are four standing committees: the Audit Committee, the Corporate Governance Committee, the Compensation Committee and the Environmental, Health and Safety Committee. Each committee includes directors who possess the relevant skills and knowledge needed to execute the committee's mandate. All of the members of the Audit Committee and the Corporate Governance Committee are independent. The majority of the members of the Compensation Committee

and the Environmental, Health and Safety Committee are independent. Each committee has a written charter that clearly defines its duties, responsibilities and the extent of its authority. The Board Mandate requires that the effectiveness of the Board, each committee and each individual director be assessed regularly.

Trilogy has also adopted the following codes and policies:

- Code of Business Conduct
- Code of Ethics for the CEO, President, CFO and Senior Financial Supervisors;
- Disclosure and Insider Trading Policy and a Whistleblower Policy;
- Environmental, Health and Safety Policy.

These policies may be viewed on Trilogy's website www.trilogyenergy.com.

More detailed information regarding Trilogy's approach to corporate governance is set forth in the Management Information and Proxy Circular dated March 3, 2006.

Health, Safety, and Environment

HEALTH AND SAFETY

Trilogy's number one priority is the health and safety of its employees and contractors. The policies, practices and procedures associated with the Trust's Health and Safety Management System are an integral part of its daily operations; endeavoring to make safety a guiding factor in all decisions with safety awareness, training and accountability being well established fundamentals of the corporate culture. Hazard and risk assessment, incident/accident reporting and investigation, and site inspections and audits, internally as well as by insurance companies and regulatory agencies, provide a means of measuring performance. As well our performance is measured through Stewardship Benchmarking with members of CAPP.

ENVIRONMENT

Environmental stewardship is an integral aspect of our operations and a significant component of Trilogy's decision making process. In acknowledging the benefits of environmental protection and the costs associated with environmental alteration and reclamation, we take a proactive approach to the impact of our activities. Trilogy participates in voluntary and mandatory reporting of air emissions and contaminants to various regulatory and industry agencies. Generated waste is identified, processed and tracked in accordance with regulatory guidelines. Spills are reported and environmental damage which occurs as a result of our business activities is repaired. An asset retirement inventory has been developed and is maintained. The Trust constantly monitors and reviews its operations to find new ways to improve its environmental performance.


CASING MATL / DIAMETER: 5 1/2 IN.
START DATE: 10/01/2006 GEOLOGIST: L. MARSHALL
E-LOGGED BY: PRECISION WIRELINE

Management's Discussion and Analysis

This Management's Discussion and Analysis ("MD&A") provides the details of the financial condition and results of operations of Trilogy Energy Trust ("Trilogy" or the "Trust") as at and for the year ended December 31, 2005, and should be read in conjunction with the Trust's consolidated financial statements and related notes for the year then ended. The consolidated financial statements have been prepared in Canadian dollars in accordance with Canadian generally accepted accounting principles ("GAAP").

This MD&A includes the historical information on financial condition and results of operations on a carve-out basis from Paramount Resources Ltd. ("Paramount") as if the Trust had operated as a stand-alone entity subject to Paramount's control prior to April 1, 2005. Commencing April 1, 2005, Trilogy holds the Trust Assets, with the earnings from April 1, 2005 being retained until distributed by the Trust. The historical information pertaining to the periods prior to April 1, 2005 may not necessarily be indicative of the results that would have been attained if the Trust had operated as a stand-alone entity for such periods.

Readers are also cautioned of the advisories on forward-looking statements, estimates, non-GAAP measures and numerical references which can be found towards the end of this MD&A. This MD&A was prepared using currently available information as of March 3, 2006.

CONTENTS OF THIS MD&A

FORMATION AND STRUCTURE OF TRILOGY

Pursuant to the plan of arrangement involving Paramount and its shareholders and optionholders as described in the Information Circular of Paramount dated February 28, 2005 (the "Plan of Arrangement"), the Trust acquired certain properties from Paramount effective April 1, 2005. These assets (the "Trust Assets") are located in the Kaybob and Marten Creek areas of Alberta. Through the Plan of Arrangement, shareholders of Paramount received, in exchange for each of their common shares, one new common share of Paramount and one unit of the Trust ("Trust Unit"). At closing, shareholders of Paramount owned 81 percent of the issued and outstanding Trust Units with the remaining 19 percent (17.7 percent at December 31, 2005) of the issued and outstanding Trust Units being held by Paramount.

Trilogy, through a wholly-owned holding trust (Trilogy Holding Trust or the "Holding Trust"), indirectly owns the Trust Assets through an operating limited partnership (Trilogy Energy LP or the "Limited Partnership"). Another wholly-owned subsidiary of the Trust, Trilogy Energy Ltd., acts as the general partner (the "General Partner") of the Limited Partnership and as administrator to Trilogy and the Holding Trust.

BUSINESS OVERVIEW, STRATEGY AND KEY PERFORMANCE DRIVERS

BUSINESS OVERVIEW

The Trust's oil and gas properties are primarily high working interest, lower decline properties that are geographically concentrated in areas that have multi-zone potential. These properties have numerous low-risk, down-spacing drilling opportunities with good access to infrastructure and processing facilities. The majority of the wells and producing infrastructure are operated by Trilogy Energy LP.

The Trust makes monthly distributions to its unitholders ("Unitholders") from the funds flow generated by the assets held by the Limited Partnership. Funds available for distribution to Unitholders flow from the Limited Partnership to the Holding Trust through a net profit interest (NPI) granted to the Holding Trust by the Limited Partnership pursuant to an NPI agreement ("NPI Agreement"). Pursuant to the NPI Agreement, the Limited Partnership makes payments to the Holding Trust from time to time as agreed to by the Holding Trust and the Limited Partnership of 99 percent of all revenues from the Limited Partnership's oil and gas properties and assets less permitted deductions. Funds flow available for distribution may also be distributed to the Holding Trust and the General Partner as distributions on units of the Limited Partnership. The payments to the Holding Trust from the Limited Partnership pursuant to the NPI Agreement and as distributions on units of the Limited Partnership, flow from the Holding Trust to the Trust primarily through cash distributions on the Holding Trust units held by the Trust. Once the funds available for distribution ("Distributable Cash") are received by the Trust, these are distributed to Unitholders by way of monthly cash distributions.

STRATEGY

The Trusts objective is to provide a stable monthly cash distribution to Unitholders and ensure that the Trust assets are maintained at a level that ensures ongoing cash flow is sustainable. Trilogy's strategy to achieve this objective is to grow through the exploitation of tight gas reserves in the Kaybob area as well as by pursuing acquisition opportunities where we can employ a similar exploitation strategy. The Kaybob and Marten Creek assets will provide long-term stable cash flows that can be grown through the successful acquisition of strategic assets that would be accretive to the Unitholders. Acquisitions by the Trust are expected to be financed through bank financing and the issuance of additional Trust units from treasury, maintaining prudent leverage.

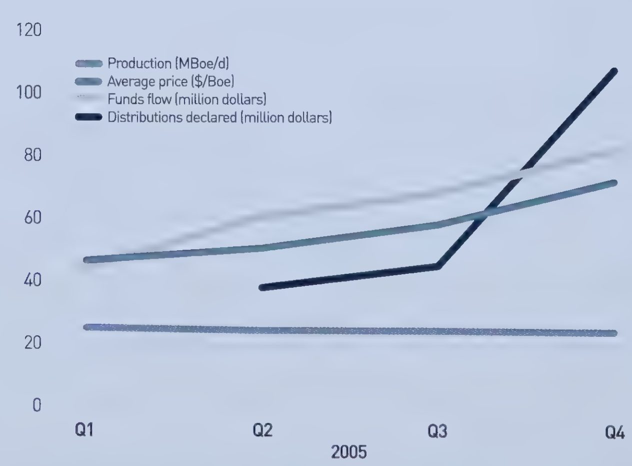
The technical expertise that has been employed at Paramount will continue to develop and exploit the reserves in Kaybob and Marten Creek. The field operation has been growing and developing the operational expertise to operate effectively and efficiently in the Kaybob area and will continue to be a part of the exploitation and production of the assets. The Trust will ensure that the field employees are trained, qualified and sufficiently experienced to perform their assigned tasks in a competent manner.

KEY PERFORMANCE DRIVERS

The Trust's ability to generate Distributable Cash is dependent upon several factors, including but not limited to, the market prices of energy commodity products, the effectiveness of the Trust's approach to manage price volatility, its capability to sustain desired levels of production, and its efficiency in developing and operating properties at minimum costs. The Trust's key measures of performance with respect to these drivers include average production per day, average realized prices, average operating costs per unit of production and average finding and development cost per unit of reserve additions.

Since the transfer of the Trust Assets to Trilogy on April 1, 2005, Trilogy has generated funds flow from operations totaling $210.8 million up to December 31, 2005, of which $190.8 million (or approximately 91 percent) was declared for distribution to Unitholders. Funds flow from operations has consistently

Key Performance Indicators



increased from quarter to quarter during 2005 as a result mainly of high energy commodity prices. The increase in funds flow triggered the increase in the amount declared for monthly distribution from the initial $0.16 per Trust Unit to $0.25 per Trust Unit effective September 2005. In addition, the Trust also declared a special distribution of $0.55 per Trust Unit in December 2005.

For the year ended December 31, 2005, the Trust reported total exploration and development expenditures of $140.2 million including the amount spent during the first quarter of 2005 of $54.1 million reported by Paramount, and the amount spent on land by the Trust from April 1, 2005 of $7.9 million. Capital expenditures (excluding acquisitions) during 2005 added proved and probable reserves of 9.9 MMBoe which is equal to 111 percent of production for the year ended December 31, 2005.

Capital spending in 2005 was higher than previously expected due to higher costs experienced by the industry in a very competitive environment. Capital costs escalated 20 to 30 percent throughout the year as a result of this competition for labour and materials. These costs are expected to remain high through 2006. Additional capital was reported in 2005 on projects that were initiated in 2004 and completed in 2005.

SUBSEQUENT EVENT

On February 28, 2006, Trilogy entered into an agreement with Redsky Energy Ltd. (Redsky) providing for the acquisition of all of the shares of Redsky for consideration of 6,500,000 Trilogy Trust Units pursuant to a plan of arrangement. Trilogy is expected to assume negligible net debt as a result of this transaction.

The completion of the plan of arrangement is subject to various conditions, including receipt of all required regulatory, shareholder and court approvals. A special meeting of shareholders of Redsky is expected to be called in March 2006.

FOURTH QUARTER VS. THIRD QUARTER 2005 PERFORMANCE

(thousands of dollars)	Funds Flow from Operations	Net Earnings (Loss)
Third quarter 2005	68,170	(2,529)
Increase in petroleum and natural gas sales due to increase in prices	30,819	30,819
Decrease in petroleum and natural gas sales due to decrease in production	(1,939)	(1,939)
Increase in realized loss on financial instruments	(7,486)	(7,486)
Increase in royalties due to the increase in petroleum and natural gas sales	(9,802)	(9,802)
Decrease in operating expenses	2,278	2,278
Decrease (increase) in general and administrative expenses	(156)	3,198
Decrease in depletion and depreciation	—	5,912
Decrease in unrealized loss on financial instruments	—	65,279
Change in other items	214	1,945
Fourth quarter 2005	82,098	87,675

- Natural gas prices averaged $12.05/Mcf during the fourth quarter 2005 compared to $9.31/Mcf during the third quarter 2005. Oil and natural gas liquids prices averaged $71.38/Bbl during the fourth quarter 2005 compared to $67.72/Bbl during the third quarter 2005.

- The average natural gas sales volume of 115.7 MMcf/d for the fourth quarter 2005 was slightly higher than the average natural gas volume of 115.5 MMcf/d for the third quarter 2005 while oil and natural gas liquids average production decreased to 4,826 Bbl/d during the fourth quarter 2005 from 5,154 Bbl/d during the third quarter 2005. The slight decline in total production is due mainly to the delayed completion of tie in activities as a result of unfavourable weather conditions.

- The increase in average energy commodity prices has resulted in an increase in the realized loss on financial instruments during the fourth quarter compared to the previous quarter. However, Trilogy has entered into new financial sales contracts during the fourth quarter 2005 resulting in an unrealized gain on financial instruments of $36.3 million during the fourth quarter compared to an unrealized loss on financial instruments of $29.0 million during the third quarter 2005.

- Royalties as a percentage of petroleum and natural gas sales were at 22 percent for the third quarter 2005 and 24 percent for the fourth quarter 2005. The increase in royalties as a percentage of petroleum and natural gas sales was due partly to the price received by the Trust changing in relation to the reference price on which royalties are calculated.

- Operating expenses per unit of production decreased to $7.55/Boe during the fourth quarter 2005 compared to $8.48/Boe during the previous quarter. This is due mainly to non-recurring workover expenditures incurred during the third quarter 2005.
- General and administrative expenditures excluding non-cash unit-based compensation expenditures were relatively consistent during the third and fourth quarters of 2005. Total general and administrative expenses (including non-cash unit-based compensation) decreased during the fourth quarter due mainly to the decline in accrued compensation expense associated with the Trust's unit appreciation plan. The reduction in market value of Trilogy shares from $27.90 per Trust Unit as at September 30, 2005 to $23.80 per Trust Unit as at December 31, 2005 has caused such accrued compensation expense to decrease to $1.6 million for the fourth quarter 2005 from $5.5 million for the third quarter 2005.
- The decrease in depletion and depreciation expense is due mainly to the increase in reserves at year end and the impact of the downward revision on October 1, 2005 of asset retirement obligation as disclosed in note 6 to the consolidated financial statements.
- The change in other expenditures impacting net earnings is mainly the result of lower geological and geophysical expenditures incurred in the fourth quarter 2005 compared to the previous quarter.

LIQUIDITY AND CAPITAL RESOURCES

CONTRACTUAL OBLIGATIONS

The Trust has the following contractual obligations as at December 31, 2005:

(thousands of dollars)	Less than 1 Year	1 – 3 years	4 – 5 years	After 5 years	Total
Long-term debt[1]	—	108,375	—	—	108,375
Unit-based compensation liability	5,810	2,876	—	—	8,686
Asset retirement obligations	—	—	—	42,706	42,706
Pipeline transportation commitments[2]	12,299	19,692	19,259	40,866	92,116
Office premises operating leases	644	3,460	3,325	10,666	18,095
Total	18,753	134,403	22,584	94,238	269,978

(1) Net of deposit-in-trust for repayment of $50 million.
(2) Some of the pipeline transportation commitments are covered by letters of credit issued by the Trust totaling $9.6 million as at December 31, 2005.

LONG-TERM DEBT

Long-term debt represents the outstanding draw downs out of the Trust's revolving credit facility with a syndicate of Canadian chartered banks. The revolving feature of the Trust's credit facility expires on March 31, 2006 if not extended. Pursuant to the terms of the credit agreement, the Trust has requested an extension of one year on the revolving feature. The Trust anticipates the request will be approved and the revolving phase of the credit facility will be extended to March 30, 2007. Upon the expiry of the credit agreement's revolving phase, amounts outstanding will have a term maturity date of one additional year.

The earliest possible due date has been used in classifying the estimated payment date of the long-term debt only for purposes of the contractual obligations table above.

The letters of credit mentioned above reduce the amount available under the Trust's working capital facility.

UNIT-BASED COMPENSATION LIABILITY

Unit-based compensation liability represents the accrued compensation expense relating to the unit appreciation plan discussed in note 10 to the consolidated financial statements. This liability is the estimated appreciation value of outstanding unit appreciation rights as at December 31, 2005 which consists of the appreciation value of vested unit rights and amortized appreciation value of unvested unit rights over the vesting period. This amount is periodically revalued with respect to outstanding unit rights due to the fluctuation in the market price of Trust Units and the increased elapsed period of unvested unit rights.

ASSET RETIREMENT OBLIGATIONS

The Trust recognizes the fair value of asset retirement costs relating to its petroleum and natural gas properties when a reasonable estimate of the fair value can be made (note 6 to the consolidated financial statements). These liabilities will be settled based on the expected life of the underlying assets, the majority of which are not expected to be paid for several years or decades in the future and will be funded from the general resources of the Trust at that time. These liabilities are subsequently adjusted for the passage of time (accretion) and for revisions in either the timing or the amount of the original estimated cash flows associated with each liability.

OTHER FIRM COMMITMENTS

The Trust has minimum volume commitments to gas transportation service providers under agreements expiring in 2011 and 2015. In addition, the Trust has entered into operating lease agreements with office space lessors the latest of which expires in 2017. No liabilities relating to future years have been recorded in the Trust's financial statements as at December 31, 2005 arising from these commitments.

The Trust also has an outstanding physical contract to sell 10,000 GJ/d of natural gas at an AECO fixed price of $14.04 from January 2004 to March 2006.

EQUITY OFFERING

On December 30, 2005, the Trust completed the offering of 6,000,000 Trust Units for net proceeds of $140.6 million, after commissions and estimated expenses. The net proceeds from this offering were used to repay credit facilities and augment operating fund requirements.

As at December 31, 2005 and March 3, 2006, the Trust had 85,133,395 Trust Units outstanding.

Funds Flow from Operations and Cash Distributions

	Nine Months Ended Dec. 31	Years Ended December 31		
(thousands of dollars except where stated otherwise)	2005	2005	2004	2003
Cash flows from operating activities	**196,742**	**192,501**	154,505	67,640
Net changes in operating working capital	**14,014**	**62,263**	11,997	4,835
Funds flow from operations	**210,756**	**254,764**	**166,502**	**72,475**
Distributions declared[1]	**190,763**	**—**	—	—
Distribution payout percentage	**90%**	**—**	—	—

(1) Distributions to unitholders commenced only after the transfer of the Trust Assets to the Trust on April 1, 2005.

Funds flow from operations increased from year to year due mainly to the increases in net earnings as discussed in the Results of Operations section. The amount of future funds flow from operations is highly sensitive to changes in commodity prices, interest rates and other factors as described in the Sensitivity Analysis section of this MD&A.

Trilogy's approach is to maximize the distribution of distributable earnings to Unitholders. The amount of distributions in the future is highly dependent upon the amount of funds flow to be generated from operations and cannot be assured. Please refer to the Income Tax Section of this MD&A for the taxability of the Trust and its Unitholders.

WORKING CAPITAL

(thousands of dollars)	2005	2004
Current assets	**86,169**	78,102
Current liabilities	**161,471**	(88,351)
Net working capital deficiency	**(75,302)**	**(10,249)**

The increase in the working capital deficiency from $10.2 million as at December 31, 2004 to $75.3 million as at December 31, 2005 is due mainly to the accrued December 2005 monthly and special distributions payable of $68.1 million and the current portion of accrued unit-based compensation of $5.8 million as at December 31, 2005 which did not exist as at December 31, 2004. In addition, the net financial instruments asset of $11.2 million as at December 31, 2004 became a $3.4 million financial instruments liability as at December 31, 2005. Financial instruments assets and liabilities are recognized on the fair value of forward financial sales contracts as discussed below.

The Trust's working capital deficiency is funded by cash flows from operations and draw downs from the Trust's credit facility.

RISK MANAGEMENT

To protect cash flows against commodity price volatility, the Trust utilizes, from time to time, forward commodity price contracts that require financial settlement between counterparties. The financial instruments program is generally for periods of less than one year and would not exceed 50 percent of Trilogy's current production volumes.

The Trust had forward financial commodity sales contracts outstanding as at December 31, 2005 as disclosed in note 11 to the consolidated financial statements. The Trust also entered into forward financial commodity sales and purchase contracts subsequent to December 31, 2005 as disclosed in note 15 to the consolidated financial statements.

The Trust follows the recommendations set out in Accounting Guideline ("AcG") 13 – Hedging Relationships and Emerging Issues Committee Abstract 128 – Accounting for Trading, Speculative or Non-Hedging Derivative Financial Instruments issued by the Canadian Institute of Chartered Accountants. According to these requirements, financial instruments that do not qualify as hedges under AcG 13 or are not designated as hedges are recorded in the consolidated balance sheets as either an asset or a liability, with changes in fair value recorded in net earnings. The Trust has elected not to designate any of its financial instruments as a hedge and accordingly, has used mark-to-market accounting for these instruments.

The change in the fair value of outstanding financial instruments is presented as 'unrealized gain (loss) on financial instruments' in the consolidated statements of earnings. Gains or losses arising from monthly settlement with counterparties are presented as 'realized gain (loss) on financial instruments. The amounts of unrealized and realized gain (loss) on financial instruments during the periods are as follows:

(thousands of dollars)	**Nine Months Ended Dec. 31, 2005**	**Years Ended December 31 2005**	**2004**	**2003**
Realized loss on financial instruments	**(16,341)**	**(18,627)**	(869)	(27,621)
Unrealized gain (loss) on financial instruments	**393**	**(14,542)**	11,154	—
Total gain (loss) on financial instruments	**(15,948)**	**(33,169)**	10,285	(27,621)

The mark-to-market accounting of financial instruments causes significant fluctuations in gain (loss) on financial instruments due to the volatility of energy commodity prices.

Under a services agreement described under the Related Party Transactions section, Paramount performs marketing functions on behalf of the Trust. The Trust is exposed to credit risk from financial instruments to the extent of non-performance by third parties. Credit risks associated with possible non-performance by financial instrument counterparties are minimized by entering into contracts with only highly rated counterparties and third party credit risk is controlled with credit approvals, limits on exposures to any one counterparty, and monitoring procedures.

Production is sold to a variety of purchasers under normal industry sale and payment terms. The Trust's accounts receivable are with customers and joint venture partners in the petroleum and natural gas industry and are subject to normal credit risk.

The Trust is also exposed to fluctuations in interest rates relative to its bank credit facilities as discussed above.

INCOME TAXES

Each year the Trust is required to file an income tax return and any otherwise taxable income of the Trust is allocated to Unitholders. Income of the Trust that has been paid or is payable to Unitholders, whether in cash, additional Trust Units or otherwise, will be deductible by the Trust in computing its income for tax purposes.

Future income taxes arise from differences between the accounting and tax basis of the operating entities' assets and liabilities. In our current structure, payments are made between the operating entities and the Trust, ultimately transferring any current income tax liabilities to the Unitholders. The tax-efficient structure of the Trust should minimize any income taxes being payable in the Trust or other direct/indirect subsidiaries of the Trust, and as such, no current or future income tax liabilities have been recognized in the financial statements. However, the determination of the Trust and its direct/indirect subsidiaries income and other tax liabilities require interpretation of complex laws and regulations over multiple jurisdictions. All tax filings are subject to audit and potential reassessment after the lapse of considerable time.

As at December 31, 2005, tax pools were estimated to be $131 million for tangibles and $51 million for intangibles.

CANADIAN TAXPAYERS

The Trust qualifies as a mutual fund trust under the Income Tax Act (Canada) and accordingly, Trust Units are qualified investments for Registered Retirement Savings Plans, Registered Retirement Income Funds, Registered Education Savings Plans and Deferred Profit Sharing Plans (subject to the specific provisions of any of these particular plans). To the best of our knowledge, Trilogy's foreign ownership level currently is approximated to be 15 percent. The Trust will continue to monitor the progress of any legislative changes to maintain its mutual fund trust status.

A Unitholder generally will be required to include in computing income for their particular taxation year, such portion of the net income of the Trust for a taxation year, including net realized taxable capital gains paid or payable to the Unitholder in that particular taxation year, whether received in cash, additional Trust Units or otherwise. An investor's adjusted cost basis (ACB) in a Trust Unit generally equals the purchase price of the unit less any non-taxable cash distributions received from the date of acquisition. To the extent a Unitholder's ACB is reduced below zero, such amount will be deemed to be a capital gain to the Unitholder and the Unitholder's ACB will be nil.

U.S. TAXPAYERS

Distributions paid out of the Trust's current or accumulated earnings and profits, as determined for U.S. federal income tax purposes, will be taxable as dividend income. Distributions in excess of current and accumulated earnings and profits will be a tax-free recovery of basis to the extent of the United States Holder's adjusted tax basis in the Trust Units and any remaining amount of distributions will generally be subject to tax as a capital gain. Dividends on Trust Units will generally be foreign sourced income for foreign tax credit limitation purposes and will not be eligible for a dividends received deduction.

Certain dividends received by United States individuals from a qualified foreign corporation (such as Trilogy) are subject to a maximum United States federal income tax rate of 15 percent. The United States Treasury Department has identified the Canada/United States Income Tax Treaty as a qualifying treaty. The result is that the Trust should be considered a qualified foreign corporation. To qualify for the reduced rate of taxation on dividends, a holder must satisfy certain requirements with respect to their Trust Units.

United States holders are advised to seek legal advice from their professional advisors.

RELATED PARTY TRANSACTIONS

As described in more detail in the Trust's consolidated financial statements for the year ended December 31, 2005, the following is a summary of the Trust's transactions with related parties:

- Paramount Resources, a wholly-owned subsidiary of Paramount (which owns 17.7 percent of the outstanding Trust Units at December 31, 2005), provides administrative and operating services to the Trust and its subsidiaries, pursuant to an agreement dated April 1, 2005, to assist Trilogy Energy Ltd. in carrying out its duties and obligations as general partner of Trilogy Energy LP and as the administrator of the Trust and Trilogy Holding Trust. The amount of expenses billed by Paramount Resources for such services was $4.2 million for the nine months ended December 31, 2005. The parties are now in the process of extending the terms of this agreement until March 31, 2007.
- Under a Call on Production Agreement between Trilogy Energy LP and Paramount dated March 29, 2005, Trilogy Energy LP sold 8,490,542 GJ of natural gas to Paramount for approximately $70.3 million for the period ended December 31, 2005. Such agreement was terminated by both parties on November 30, 2005.
- In addition, the Trust and Paramount also had transactions with each other arising from normal business activities.

The net amount due from Paramount arising from the above related party transactions as at December 31, 2005 was $6.4 million, including a Crown royalty deposit claim of $5.5 million which when refunded to Paramount will be collected by the Trust.

ANNUAL RESULTS OF OPERATIONS

This MD&A includes the historical information on financial condition and results of operations on a carve-out basis from Paramount Resources Ltd. ("Paramount") as if the Trust had operated as a stand-alone entity subject to Paramount's

control prior to April 1, 2005. The historical information pertaining to the periods prior to April 1, 2005 may not necessarily be indicative of the results that would have been attained if the Trust had operated as a stand-alone entity for such periods.

IMPORTANT EVENTS

The following events which took place while the Trust Assets were still under Paramount's control impact the following discussions on the Trust's results of operations:

1. **Kaybob Acquisition.** On June 30, 2004, Paramount completed an agreement to acquire oil and natural gas assets for cash consideration of $185.1 million, after adjustments. The assets acquired by Paramount are located in the Kaybob area in central Alberta, in the Fort Liard area in the Northwest Territories and in northeast British Columbia. From the properties acquired, only certain Kaybob area assets valued at $91.7 million were considered part of the Trust Assets. The consolidated financial statements of the Trust reflect the income of the properties that became part of the Trust Assets for the periods after the closing of the acquisition.

2. **Marten Creek Acquisition.** On August 16, 2004, Paramount completed the acquisition of assets in the Marten Creek area in Grande Prairie for a cash consideration of $86.9 million. All these properties were transferred as part of the Trust Assets and the income for the periods after the closing date of this acquisition is included in the Trust's consolidated financial statements.

OVERALL FINANCIAL RESULTS

(thousands of dollars except as otherwise indicated)	2005	Change from 2004	2004	Change from 2003	2003
Petroleum and natural gas sales:					
Natural gas	**395,522**	138,749	256,773	70,220	186,553
Oil and natural gas liquids	**113,359**	42,521	70,838	39,293	31,545
	508,881	181,270	327,611	109,513	218,098
Average sales volumes:					
Natural gas (Mcf/d)	**117,402**	18,953	98,449	20,880	77,569
Oil and natural gas liquids (Bbl/d)	**4,928**	1,048	3,880	1,696	2,184
Total (Boe/d)	**24,495**	4,207	20,288	5,176	15,112
Average prices before realized financial instruments and transportation (in full amounts)					
Natural gas ($/Mcf)	**9.23**	2.10	7.13	0.54	6.59
Oil and natural gas liquids ($/Bbl)	**63.03**	13.14	49.89	10.31	39.58
Average prices after realized financial instruments and before transportation (in full amounts):					
Natural gas ($/Mcf)	**8.86**	1.64	7.22	1.54	5.68
Oil and natural gas liquids ($/Bbl)	**61.57**	14.80	46.77	9.01	37.76
Loss (gain) on financial instruments[1]	**33,169**	43,454	(10,285)	(37,906)	27,621
Royalties	**118,251**	50,680	67,571	22,812	44,759
Operating costs	**68,145**	17,370	50,775	17,909	32,866
Transportation costs	**19,828**	1,938	17,890	2,055	15,835
Depletion and depreciation	**128,021**	26,801	101,220	26,816	74,404
General and administrative expenses	**22,670**	(15,577)	38,247	27,702	10,545
Interest	**9,608**	(1,350)	10,958	1,353	9,605
Other expenditures	**30,391**	29,757	634	(12,094)	12,728
Taxes	**(7,649)**	(32,707)	25,058	41,440	(16,382)
Net earnings	**86,447**	60,904	25,543	19,426	6,117

(1) See Risk Management section.

2005 VS. 2004

- Natural gas sales increased by $75.8 million due to higher average sales prices and $62.9 million due to higher sales volumes. Oil and natural gas liquids sales increased by $18.7 million due to higher average sales prices and $23.9 million due to higher sales volumes. Product sales volumes were higher in 2005 compared to 2004 as the acquisitions in 2004 mentioned above had a full year impact in 2005.
- The increase in royalties in 2005 was due mainly to the increase in petroleum and natural gas sales as noted above. As a percentage of petroleum and natural gas sales, royalties averaged 23 percent in 2005 compared to 21 percent in 2004, as the properties acquired in part of 2004 have higher royalty rates than those owned prior to such property acquisitions.
- The increase in operating costs in 2005 is attributable mainly to the higher number of producing properties and increased production arising from the property acquisitions described above. On a per unit of product sales volume basis, operating costs increased to $7.62/Boe in 2005 from $6.84/Boe in 2004 reflecting increases in the cost of goods and services in the energy sector, higher operating costs related to the acquired properties, and increased workovers.
- Depletion and depreciation expense increased by 26 percent in 2005 due mainly to higher product sales volumes. On a per unit of product sales volume basis, depletion and depreciation is up to $14.32/Boe in 2005 from $13.63/Boe in 2004 as the depletion and depreciation rates are higher for the properties acquired in part of 2004.
- General and administrative expenses decreased in 2005 compared to 2004 due mainly to the recording (on a carve-out basis from Paramount) of stock-based compensation expense of $23.7 million in 2004 compared to a unit-based compensation expense of $8.9 million in 2005.
- Interest also decreased in 2005 compared to 2004 due mainly to the lower interest rates on Trilogy's Canadian dollar denominated borrowing effective April 1, 2005. Prior to April 1, 2005, interest expense was recognized in the consolidated statements of earnings based on a deemed debt balance attributable to the Trust Assets using Paramount's borrowing rates, which were higher due to its U.S. dollar denominated debt.
- Other items consist mainly of geological and geophysical costs, dry hole costs, accretion on asset retirement obligations, and non-recurring allocated expenditures such as premium on debt exchange, foreign exchange gain (loss) and bad debt recovery, recorded on a carve-out basis from Paramount for periods prior to April 1, 2005. The increase in other expenditures is due mainly to the increases in geological and geophysical costs of $1.3 million, dry hole costs of $2.6 million, non-recurring allocated expenditures of $23.8 million and a decline in bad debt recovery of $3.2 million, partially offset by a decline in loss on sale of property, plant and equipment of $1.5 million.
- No amounts in respect of tax have been recorded since the Trust owned the assets. Prior to April 1, 2005, the liability method was used to calculate future taxes.

2004 VS. 2003

- Natural gas sales increased by $15.3 million due to higher average sales prices and $54.9 million due to higher sales volumes. Oil and natural gas liquids sales increased by $8.2 million due to higher average sales prices and $31.1 million due to higher sales volumes. Product sales volumes were higher in 2004 compared to 2003 mainly as a result of the acquisitions in 2004 as mentioned above.
- The increase in royalties in 2004 was due mainly to the increase in petroleum and natural gas sales as noted above. As a percentage of petroleum and natural gas sales, royalties averaged about 21 percent for both 2004 and 2003.
- The increase in operating costs in 2004 is attributable mainly to the higher number of producing properties and increased production arising from the property acquisitions described above. On a per unit of product sales volume basis, operating costs increased to $6.84/Boe in 2004 from $5.96/Boe in 2003 due mainly to higher operating costs related to the acquired properties, and increased workovers.

- Depletion and depreciation expense increased by 36 percent in 2004 due mainly to higher product sales volumes. On a per unit of product sales volume basis, depletion and depreciation is up slightly to $13.63/Boe in 2004 from $13.49/Boe in 2003 as the depletion and depreciation rates are higher for the properties acquired in part of 2004.
- General and administrative expenses increased in 2004 compared to 2003 due mainly to the recording (on a carve-out basis from Paramount) of stock-based compensation expense of $23.7 million in 2004.
- Interest increased in 2004 compared to 2003 due mainly to the increased borrowings to fund the acquisitions in 2004.
- The decrease in other expenditures is due mainly to non-recurring allocated credits in 2004 that were $7.0 million in excess of 2003, the recovery of a bad debt for $3.1 million that had been expensed in 2003, a decline in dry hole expense of $1.1 million and a decline in write downs of $1.5 million. These amounts were offset by increases in accretion expense of $2.4 million and geological and geophysical expense of $1.6 million.

OTHER ANNUAL FINANCIAL INFORMATION

As the transfer of the Trust Assets from Paramount to Trilogy did not occur until April 1, 2005, financial information prior to April 1, 2005 was prepared on a carve-out basis from Paramount's consolidated financial statements.

(thousands of dollars)	2005	2004	2003
Capital expenditures (excluding acquisitions and dispositions)	**141,701**	101,628	70,318
Total assets	**777,793**	778,147	543,304
Equity	**462,365**	532,430	384,140

The increase in total assets in 2005 compared to 2004 due to capital spending and favourable results of operations was offset by distributions paid by the Trust to unitholders from April 1, 2005 to December 31, 2005. The capital spending in 2004 and acquisitions described above caused the significant increases in total assets and equity from 2003 to 2004.

WELLS DRILLED

	2005		2004		2003	
(number of wells)	Gross[1]	Net[2]	Gross[1]	Net[2]	Gross[1]	Net[2]
Natural gas	**66.0**	**57.7**	64.0	47.8	63.0	39.9
Oil	**8.0**	**5.3**	8.0	6.2	10.0	8.0
Dry	**5.0**	**2.4**	1.0	0.3	0.0	0.0
Total	**79.0**	**65.4**	73.0	54.3	73.0	47.9

(1) "Gross" wells means the number of wells in which Trilogy has a working interest or a royalty interest that may be converted to a working interest.

(2) "Net" wells means the aggregate number of wells obtained by multiplying each gross well by Trilogy's percentage of working interest.

CAPITAL EXPENDITURES

(thousands of dollars)	2005	2004	2003
Land	**10,564**	12,052	3,366
Geological and geophysical	**3,145**	1,854	211
Drilling	**96,718**	64,102	51,054
Production equipment and facilities	**29,791**	23,620	15,234
Exploration and development expenditures	**140,218**	101,628	69,865
Proceeds received from property dispositions	**(193)**	(127)	(3,331)
Property acquisitions	**6,544**	172,541	628
Other	**1,483**	—	453
Net capital expenditures	**148,052**	274,042	67,615

Exploration and development expenditures increased continuously from 2003 to 2005 due primarily to increasing development activities on a year-to-year basis resulting from the property acquisitions described above and rising costs of services.

QUARTERLY FINANCIAL INFORMATION

(thousands of dollars except per unit amounts)	2005 4th Quarter	2005 3rd Quarter	2005 2nd Quarter	2005 1st Quarter[1]
Net revenue	**145,643**	67,637	80,928	63,478
Net earnings (loss)	**87,675**	(2,529)	17,370	(16,069)
Earnings (loss) per Trust Unit[2]				
Basic	**1.11**	(0.03)	0.22	(0.20)
Diluted	**1.11**	(0.03)	0.22	(0.20)

(thousands of dollars except per unit amounts)	2004[1] 4th Quarter	2004[1] 3rd Quarter	2004[1] 2nd Quarter	2004[1] 1st Quarter
Net revenue	94,891	76,869	52,483	46,082
Net earnings (loss)	(5,478)	17,041	6,002	7,978
Earnings (loss) per Trust Unit[2]				
Basic	(0.07)	0.22	0.08	0.10
Diluted	(0.07)	0.22	0.08	0.10

(1) The quarterly financial information prior to the second quarter of 2005 was prepared on a carve-out basis from Paramount as the Trust did not own the Trust Assets prior to April 1, 2005.

(2) Earnings (loss) per unit presented for all periods prior to the fourth quarter 2005 are based on the weighted average number of outstanding Trust Units of 79,133,395 for the six months ended September 30, 2005.

Total revenue and net earnings fluctuated from quarter to quarter during the last three quarters of 2005 due mainly to the unrealized gains or losses on financial instruments. There was an unrealized financial instrument gain of $36.3 million for the fourth quarter 2005, unrealized financial instrument loss of $29.0 million for the third quarter 2005 and unrealized financial instrument loss of $6.8 million for the second quarter 2005.

Total revenue for the first quarter of 2005 declined from the fourth quarter of 2004 as a result mainly of the realized and unrealized loss on financial instruments of $17.2 million in the first quarter of 2005 compared to a gain of $15.8 million in the fourth quarter of 2004. This change also contributed to the increase in net loss from the fourth quarter of 2004 to the first quarter of 2005. In addition, a debt exchange premium expense of $15.8 million was recorded on a carve-out basis during the first quarter of 2005.

Total revenue increased consistently from quarter to quarter in 2004 as energy commodity prices continued to increase. In addition, the property acquisitions described above increased production volumes in the third and fourth quarters of 2004 contributing to significant increases in total revenue during those periods. There is a resulting net loss during the fourth quarter 2004 despite a significant increase in total revenue due mainly to the recording (on a carve-out basis) of stock-based compensation expense of $23.7 million. Paramount recorded a stock option liability using the intrinsic value method to account for stock options as at December 31, 2004.

OUTLOOK AND SENSITIVITY ANALYSIS

The Trust's earnings and funds flow are highly sensitive to changes in commodity prices, exchange rates and other factors that are beyond the control of the Trust. Volatility in commodity prices creates uncertainty as to the Trust's cash flow and capital expenditure budget. The Trust will assess results throughout the year and revise estimates as necessary to reflect current information. The analysis below reflects the magnitude of the sensitivities on the Trust's cash flow using the following base assumptions:

Average Production	
Natural gas	120,000 Mcf/d
Crude oil/liquids	5,000 Bbl/d
Average Prices	
Natural gas	Cdn$8.00/Mcf
Crude oil/liquids	US$65.00/Bbl
Exchange rate (US$/Cdn$)	$0.85

The estimated impact on annual cash flow of variations in production, prices, interest and exchange rates is as follows:

Sensitivity	Estimated Effect on Annual Cash Flow (millions of dollars)
Natural gas price change of $0.10/Mcf	2.3
Oil and natural gas liquids price change of US$1.00/Bbl (WTI)	0.4
US dollar to Canadian dollar exchange rate fluctuation of $0.01	3.4
Average interest rate change of 1%	2.0

CRITICAL ACCOUNTING ESTIMATES

The MD&A is based on the Trust's consolidated financial statements, which have been prepared in Canadian dollars in accordance with GAAP. The application of GAAP requires management to make estimates, judgments and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities, if any, at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Trilogy bases its estimates on historical experience and various other assumptions that are believed to be reasonable under the circumstances. Actual results could differ from these estimates under different assumptions or conditions.

The following is a discussion of the critical accounting estimates that are inherent in the preparation of the Trust's consolidated financial statements and notes thereto.

ACCOUNTING FOR PETROLEUM AND NATURAL GAS OPERATIONS

Under the successful efforts method of accounting, the Trust capitalizes only those costs that result directly in the discovery of petroleum and natural gas reserves, including acquisitions, successful exploratory wells, development costs and the costs of support equipment and facilities. Exploration expenditures, including geological and geophysical costs, lease rentals, and exploratory dry holes are charged to earnings (loss) in the period incurred. Certain costs of exploratory wells are capitalized pending determination that proved reserves have been found. Such determination is dependent upon, among other things, the results of planned additional wells and the cost of required capital expenditures to produce the reserves found.

The application of the successful efforts method of accounting requires management's judgment to determine the proper designation of wells as either developmental or exploratory, which will ultimately determine the proper accounting treatment of the costs incurred. The results of a drilling operation can take considerable time to analyze, and the determination that proved reserves have been discovered requires both judgment and application of industry experience. The evaluation of petroleum and natural gas leasehold acquisition costs requires management's judgment to evaluate the fair value of exploratory costs related to drilling activity in a given area.

RESERVE ESTIMATES

Estimates of the Trust's reserves included in its consolidated financial statements are prepared in accordance with guidelines established by the Alberta Securities Commission. Reserve engineering is a subjective process of estimating underground accumulations of petroleum and natural gas that cannot be measured in an exact manner. The process relies on interpretations of available geological, geophysical, engineering and production data. The accuracy of a reserve estimate is a function of the quality and quantity of available data, the interpretation of that data, the accuracy of various mandated economic assumptions and the judgment of the persons preparing the estimate.

Trilogy's reserve information is based on estimates prepared by its independent petroleum consultants. Estimates prepared by others may be different than these estimates. Because these estimates depend on many assumptions, all of which may differ from actual results, reserve estimates may be different from the quantities of petroleum and natural gas that are ultimately recovered. In addition, the results of drilling, testing and production after the date of an estimate may justify revisions to the estimate. Trilogy intends that 100 percent of its annual reserves information will be evaluated by independent petroleum consultants.

The present value of future net revenues should not be assumed to be the current market value of the Trust's estimated reserves. Actual future prices, costs and reserves may be materially higher or lower than the prices, costs and reserves used for the future net revenue calculations.

The estimates of reserves impact depletion, dry hole expenses and asset retirement obligations. If reserve estimates decline, the rate at which the Trust records depletion increases, reducing net earnings. In addition, changes in reserve estimates may impact the outcome of Trilogy's assessment of its petroleum and natural gas properties for impairment.

IMPAIRMENT OF PETROLEUM AND NATURAL GAS PROPERTIES

The Trust reviews its proved properties for impairment annually on a field basis. For each field, an impairment provision is recorded whenever events or circumstances indicate that the carrying value of those properties may not be recoverable. The impairment provision is based on the excess of carrying value over fair value. Fair value is defined as the present value of the estimated future net revenues from production of total proved and probable petroleum and natural gas reserves, as estimated by the Trust on the balance sheet date. Reserve estimates, as well as estimates for petroleum and natural gas prices and production costs may change, and there can be no assurance that impairment provisions will not be required in the future.

Unproved leasehold costs and exploratory drilling in progress are capitalized and reviewed periodically for impairment. Costs related to impaired prospects or unsuccessful exploratory drilling are charged to earnings. Acquisition costs for leases that are not individually significant are charged to earnings as the related leases expire. Further impairment expense could result if petroleum and natural gas prices decline in the future or if negative reserve revisions are recorded, as it may be no longer economic to develop certain unproved properties. Management's assessment of, among other things, the results of exploration activities, commodity price outlooks and planned future development and sales, impacts the amount and timing of impairment provisions.

ASSET RETIREMENT OBLIGATIONS

The asset retirement obligations recorded in the consolidated financial statements are based on an estimate of the fair value of the total costs for future site restoration and abandonment of the Trust's petroleum and natural gas properties. This estimate is based on management's analysis of production structure, reservoir characteristics and depth, market demand for equipment, currently available procedures, the timing of asset retirement expenditures and discussions with construction and engineering consultants. Estimating these future costs requires management to make estimates and judgments that are subject to future revisions based on numerous factors, including changing technology and political and regulatory environments.

RECENT ACCOUNTING PRONOUNCEMENT

FINANCIAL INSTRUMENTS, OTHER COMPREHENSIVE INCOME AND EQUITY

The Canadian Institute of Chartered Accountants (the "CICA") has issued a new standard that sets out comprehensive requirements for recognition and measurement of financial instruments. Under this new standard, an entity would recognize a financial asset or liability only when the entity becomes a party to the contractual provisions of the financial instrument. Financial assets and financial liabilities would, with certain exceptions, be initially measured at fair value. After initial recognition, the measurement of financial assets would vary depending on the category of the asset: financial assets held for trading (at fair value with the unrealized gains and losses on assets recorded in income), held-to-maturity investments (at amortized cost), loans and receivables (at amortized cost), and available-for-sale financial assets (at fair value with the unrealized gains and losses on assets recorded in comprehensive income). Financial liabilities held for trading would be subsequently measured at fair value while all other financial liabilities would be subsequently measured at amortized cost using the effective interest method.

In conjunction with the new standard on financial instruments as discussed above, a new standard on reporting and display of comprehensive income has also been issued. A statement of comprehensive income would be included in a full set of financial statements for both interim and annual periods under this new standard. Comprehensive income is defined as the change in equity (net assets) of an enterprise during a period from transactions and other events and circumstances from non-owner sources. The new statement would present net income and each component to be recognized in other comprehensive income. Likewise, the CICA has adopted a new standard on Equity that would require the separate presentation of: the components of equity (retained earnings, accumulated other comprehensive income, the total of retained earnings and accumulated other comprehensive income, contributed surplus, share capital and reserves); and the changes in equity arising from each of these components of equity.

These new standards are expected to be effective for Trilogy for the year ending December 31, 2007.

RISKS AND UNCERTAINTIES

Entities involved in the exploration for and production of oil and natural gas face a number of risks and uncertainties inherent in the industry. Trilogy's performance is influenced by commodity pricing, transportation and marketing constraints and government regulation and taxation.

Natural gas prices are influenced by the North American supply and demand balance as well as transportation capacity constraints. Seasonal changes in demand, which are largely influenced by weather patterns, also affect the price of natural gas.

Stability in natural gas pricing is available through the use of short- and long-term contract arrangements. Trilogy utilizes a combination of these types of contracts, as well as spot markets, in its natural gas pricing strategy. As the majority of the Trust's natural gas sales are priced to U.S. markets, the Canada/U.S. exchange rate can strongly affect revenue.

Oil prices are influenced by global supply and demand conditions as well as by worldwide political events. As the price of oil in Canada is based on a U.S. benchmark price, variations in the Canada/U.S. exchange rate further affect the price received by Trilogy for its oil.

The Trust's access to oil and natural gas sales markets is restricted, at times, by pipeline capacity. In addition, it is also affected by the proximity of pipelines and availability of processing equipment. Trilogy intends to control as much of its marketing and transportation activities as possible in order to minimize any negative impact from these external factors.

The oil and gas industry is subject to extensive controls, regulatory policies and income taxes imposed by the various levels of government. These controls and policies, as well as income tax laws and regulations, are amended from time to time. Trilogy has no control over government intervention or taxation levels in the oil and gas industry; however, it operates in a manner intended to ensure that it is in compliance with all regulations and is able to respond to changes as they occur.

Trilogy's operations are subject to the risks normally associated with the oil and gas industry including hazards such as unusual or unexpected geological formations, high reservoir pressures and other conditions involved in drilling and operating wells. The Trust attempts to minimize these risks using prudent safety programs and risk management, including insurance coverage against potential losses.

The Trust recognizes that the industry is faced with an increasing awareness with respect to the environmental impact of oil and gas operations. Trilogy has reviewed the environmental risks to which it is exposed and has determined that there is no current material impact on the Trust's operations; however, the cost of complying with environmental regulations is increasing. Trilogy intends to ensure continued compliance with environmental legislation.

FINANCIAL REPORTING DISCLOSURE CONTROLS

Management has assessed the effectiveness of the Trust's financial reporting disclosure controls and procedures as at December 31, 2005, and has concluded that such financial reporting disclosure controls and procedures were effective as at that date.

ADVISORIES

FORWARD-LOOKING STATEMENTS AND ESTIMATES

Certain statements included or incorporated by reference in this document constitute forward-looking statements under applicable securities legislation. Forward-looking statements or information typically contain statements with words such as "anticipate", "believe", "expect", "plan", "intend", "estimate", "propose", or similar words suggesting future outcomes or statements regarding an outlook. Forward looking statements or information in this document include but are not limited to capital expenditures, business strategy and objectives, net revenue, future production levels, development plans and the timing thereof, operating and other costs, royalty rates, etc.

Such forward-looking statements or information are based on a number of assumptions which may prove to be incorrect. In addition to other assumptions identified in this document, assumptions have been made regarding, among other things:

- the ability of Trilogy to obtain equipment, services and supplies in a timely manner to carry out its activities;

- the ability of Trilogy to market oil and natural gas successfully to current and new customers;
- the timing and costs of pipeline and storage facility construction and expansion and the ability to secure adequate product transportation;
- the timely receipt of required regulatory approvals;
- the ability of Trilogy to obtain financing on acceptable terms;
- currency, exchange and interest rates; and
- future oil and gas prices.

Although Trilogy believes that the expectations reflected in such forward-looking statements or information are reasonable, undue reliance should not be placed on forward-looking statements because Trilogy can give no assurance that such expectations will prove to be correct. Forward-looking statements or information are based on current expectations, estimates and projections that involve a number of risks and uncertainties which could cause actual results to differ materially from those anticipated by Trilogy and described in the forward-looking statements or information. These risks and uncertainties include, but are not limited to:

- the ability of management to execute its business plan;
- the risks of the oil and gas industry, such as operational risks in exploring for, developing and producing crude oil and natural gas and market demand;
- risks and uncertainties involving the geology of oil and gas deposits;
- risks inherent in Trilogy's marketing operations, including credit risk;
- the uncertainty of reserves estimates and reserves life;
- the uncertainty of estimates and projections relating to production, costs and expenses;
- potential delays or changes in plans with respect to exploration or development projects or capital expenditures;
- Trilogy's ability to enter into or renew leases;
- fluctuations in oil and gas prices, foreign currency exchange rates and interest rates;
- health, safety and environmental risks;
- uncertainties as to the availability and cost of financing;
- the ability of Trilogy to add production and reserves through development and exploration activities;
- general economic and business conditions;
- the possibility that government policies or laws may change or governmental approvals may be delayed or withheld;
- uncertainty in amounts and timing of royalty payments;
- risks associated with existing and potential future law suits and regulatory actions against Trilogy; and
- other risks and uncertainties described elsewhere in this document or in Trilogy's other filings with Canadian securities authorities.

The forward-looking statements or information contained in this document are made as of the date hereof and Trilogy undertakes no obligation to update publicly or revise any forward-looking statements or information, whether as a result of new information, future events or otherwise, unless so required by applicable securities laws.

NON-GAAP MEASURES

In this document, Trilogy uses the term "funds flow from operations", a non GAAP measure, as indicators of Trilogy's financial performance. Funds flow from operations do not have standardized meanings prescribed by Canadian generally accepted accounting principles ("GAAP") and, therefore, are unlikely to be comparable to similar measures presented by other issuers.

"Funds flow from operations" refers to the cash flows from operating activities before net changes in operating working capital. Management of Trilogy believes that "funds flow from operations" provides useful information to investors as an indicative measure of performance. The most directly comparable measure to "funds flow from operations" calculated in accordance with GAAP is the cash flows from operating activities. "Funds flow from operations" can be reconciled to cash flows from operating activities by adding (deducting) the net change in working capital as shown in the consolidated statements of cash flows.

Investors are cautioned that the Non-GAAP Measures should not be considered in isolation or construed as alternatives to their mostly directly comparable measure calculated in accordance with GAAP, as set forth above, or other measures of financial performance calculated in accordance with GAAP.

NUMERICAL REFERENCES

All references in this MD&A are to Canadian dollars unless otherwise indicated.

This document contains disclosure expressed as "Boe", "MBoe", "Boe/d", "Mcf", "Mcf/d", "MMcf", "MMcf/d", and "Bcf". All oil and natural gas equivalency volumes have been derived using the ratio of six thousand cubic feet of natural gas to one barrel of oil. Equivalency measures may be misleading , particularly if used in isolation. A conversion ratio of six thousand cubic feet of natural gas to one barrel of oil is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the well head.

ADDITIONAL INFORMATION

Trilogy is a petroleum and natural gas-focused Canadian energy trust. Trilogy's Trust Units are listed on the Toronto Stock Exchange under the symbol "TET.UN". Additional information about Trilogy is available at www.sedar.com.


STRING OUT: JANUARY '02 02/06
WELDED OUT JANUARY '07 07/06

Management's Report

The accompanying consolidated financial statements of Trilogy Energy Trust and all the information in this Annual Report are the responsibility of management and have been approved by the Board of Directors. The consolidated financial statements have been prepared by management in accordance with Canadian generally accepted accounting principles. When alternative accounting methods exist, management has chosen those it deems most appropriate in the circumstances. Financial statements are not precise since they include certain amounts based on estimates and judgments. Management has determined such amounts on a reasonable basis in order to ensure that the consolidated financial statements are presented fairly, in all material respects. The financial information contained elsewhere in this report has been reviewed to ensure consistency with the consolidated financial statements.

Management maintains systems of internal accounting and administrative controls of high quality, consistent with reasonable cost. Such systems are designed to provide reasonable assurance that the financial information is relevant, reliable and accurate and that the Trust's assets are appropriately accounted for and adequately safeguarded.

The Audit Committee of the Board of Directors is comprised of non-management directors. The Audit Committee meets quarterly with management as well as the external auditors to discuss auditing matters and financial reporting issues and to satisfy itself that each party is properly discharging its responsibility. The Audit Committee also meets with management and the external auditors to discuss internal controls over the financial reporting process and to review the financial sections of the Annual Report. The Audit Committee reports its findings to the Board of Directors for consideration when approving the consolidated financial statements for issuance to the shareholders. The Audit Committee also considers, for review by the Board of Directors and approval by the Unitholders, the engagement or re-appointment of the external auditors.

The consolidated financial statements have been audited by PricewaterhouseCoopers LLP, the external auditors. PricewaterhouseCoopers LLP have full and free access to the Audit Committee and management.

Jim H.T. Riddell
Chief Executive Officer

Bernard K. Lee
Chief Financial Officer

Auditors' Report

To the Unitholders of Trilogy Energy Trust

We have audited the consolidated balance sheet of **Trilogy Energy Trust** as at December 31, 2005 and the consolidated statements of earnings and accumulated earnings and cash flows for the period April 1, 2005 to December 31, 2005. These financial statements are the responsibility of the Trust's management. Our responsibility is to express an opinion on these financial statements based on our audit.

We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Trust as at December 31, 2005 and the results of its operations and its cash flows for the period April 1, 2005 to December 31, 2005 in accordance with Canadian generally accepted accounting principles.

PricewaterhouseCoopers LLP

Chartered Accountants

February 28, 2006
Calgary, Alberta

Consolidated Balance Sheets

As at December 31 (thousands of dollars)	2005	2004 (Note 2)
ASSETS		
Current Assets		
Accounts receivable	$ 73,001	$ 63,851
Due from related party (note 12)	6,439	—
Financial instruments (note 11)	5,830	12,413
Prepaid expenses	899	1,838
	86,169	78,102
Property, plant and equipment (note 5)	672,224	680,645
Goodwill (note 1)	19,400	19,400
	$ 777,793	$ 778,147
LIABILITIES AND UNITHOLDERS' EQUITY		
Current liabilities		
Accounts payable and accrued liabilities	$ 78,334	$ 87,091
Distributions payable (includes due to related party of $12.0 million)	68,107	—
Unit-based compensation liability (note 10)	5,810	—
Financial instruments (note 11)	9,220	1,260
	161,471	88,351
Long-term debt (note 7)	108,375	—
Unit-based compensation liability – net of current portion (note 10)	2,876	—
Asset retirement obligations (note 6)	42,706	63,674
Future income taxes (note 14)	—	93,692
	153,957	157,366
Commitments and contingencies (notes 11 and 13)		
Unitholders' equity		
Unitholders' capital (note 8)	550,144	—
Contributed surplus (note 3)	468	—
Accumulated earnings	102,516	—
Accumulated distribution (note 9)	(190,763)	—
Net investment of Paramount Resources Ltd. (note 2)	—	532,430
	462,365	532,430
	$ 777,793	$ 778,147

See accompanying notes to consolidated financial statements.

On behalf of the Board

R.M. MacDonald
Director

M.H. Dilger
Director

Consolidated Statements of Earnings and Accumulated Earnings

The financial statements prior to April 1, 2005 were prepared on a carve-out basis from Paramount. As described in note 2, these financial statements may not be indicative of the results that would have been attained if the Trust had operated as a stand-alone entity for these periods.

(thousands of dollars except per unit information)	Nine Months Ended Dec. 31 2005	Years Ended December 31 2005 (unaudited) (Note 2)	2004 (Note 2)
Revenue			
Petroleum and natural gas sales	$ 402,913	$ 508,881	$ 327,611
Realized loss on financial instruments (note 11)	(16,341)	(18,627)	(869)
Unrealized gain (loss) on financial instruments (note 11)	393	(14,542)	11,154
Royalties	(92,982)	(118,251)	(67,571)
Other income	225	225	—
Net Revenue	294,208	357,686	270,325
Expenses			
Operating	52,022	68,145	50,775
Transportation	15,023	19,828	17,890
General and administrative (notes 10 and 12)	16,617	22,670	38,247
Exploration expenditures	5,437	9,444	5,563
(Gain) loss on sale of property, plant and equipment	(108)	(86)	1,376
Accretion on asset retirement obligations (note 6)	3,297	4,962	4,421
Depletion and depreciation	92,322	128,021	101,220
Interest	7,082	9,608	10,958
Bad debt recovery	—	—	(3,179)
Unrealized foreign exchange gain	—	(4,224)	(9,409)
Realized foreign exchange (gain) loss	—	4,710	(2,786)
Premium on debt exchange	—	15,810	4,648
	191,692	278,888	219,724
Earnings before taxes	102,516	78,798	50,601
Taxes (note 14)			
Future income tax expense (recovery)	—	(8,059)	21,526
Large Corporation Tax and other	—	410	3,532
	—	(7,649)	25,058
Net earnings	102,516	86,447	25,543
Accumulated earnings, beginning of period	—	—	—
(Earnings) loss allocated to net investment by Paramount Resources Ltd. (note 2)	—	16,069	(25,543)
Accumulated earnings, end of period	$ 102,516	$ 102,516	$ —
Earnings (loss) per Trust Unit (note 3)			
– Basic	$ 1.29	$ 1.09	$ 0.32
– Diluted	$ 1.29	$ 1.09	$ 0.32

See accompanying notes to consolidated financial statements.

Consolidated Statements of Cash Flows

The financial statements prior to April 1, 2005 were prepared on a carve-out basis from Paramount. As described in note 2, these financial statements may not be indicative of the results that would have been attained if the Trust had operated as a stand-alone entity for these periods.

(thousands of dollars)	Nine Months Ended Dec. 31 2005	Years Ended December 31 2005 (unaudited) (Note 2)	2004 (Note 2)
Operating activities			
Net earnings	**$ 102,516**	**$ 86,447**	$ 25,543
Add (deduct) non-cash and other items:			
Depletion and depreciation	**92,322**	**128,021**	101,220
(Gain) loss on sale of property, plant and equipment	**(108)**	**(86)**	1,376
Accretion on asset retirement obligations	**3,297**	**4,962**	4,421
Future income tax expense (recovery)	**—**	**(8,059)**	21,526
Non-cash general and administrative expenses	**9,154**	**10,186**	23,714
Non-cash loss (gain) on financial instruments	**(393)**	**14,542**	(11,154)
Unrealized foreign exchange loss [gain]	**—**	**(4,224)**	(9,409)
Asset retirement obligation expenditures	**(840)**	**(1,367)**	—
Premium on debt exchange	**—**	**15,810**	4,648
Exploration expenditures	**4,808**	**8,532**	4,617
Funds flow from operations	**210,756**	**254,764**	166,502
Net changes in operating working capital	**(14,014)**	**(62,263)**	(11,997)
	196,742	**192,501**	154,505
Financing activities			
Credit facility – draws	**659,626**	**659,626**	—
Credit facility – repayments	**(553,135)**	**(553,135)**	—
Proceeds from issuance of Trust Units	**140,576**	**140,576**	—
Net investment by Paramount Resources Ltd. (note 2)	**—**	**18,270**	103,794
Payment to Paramount Resources Ltd. re: the plan of arrangement (note 1)	**(220,000)**	**(220,000)**	—
Distributions to unitholders	**(122,656)**	**(122,656)**	—
	(95,589)	**(77,319)**	103,794
Investing activities			
Property, plant and equipment expenditures	**(85,571)**	**(138,556)**	(99,774)
Petroleum and natural gas property acquisitions (note 4)	**(6,544)**	**(6,544)**	(172,541)
Proceeds on sale of property, plant and equipment	**108**	**193**	127
Geological and geophysical costs	**(1,936)**	**(3,145)**	(1,854)
Change in investing working capital	**(7,210)**	**32,870**	15,743
	(101,153)	**(115,182)**	(258,299)
Change in cash / cash, end of period	**$ —**	**$ —**	$ —
Cash interest paid	**$ 7,356**	**$ 9,882**	$ 10,958

See accompanying notes to consolidated financial statements.

Notes to Consolidated Financial Statements

December 31, 2005 and 2004

(Tabular amounts expressed in thousands of dollars except per unit information.)

1. STRUCTURE AND FORMATION OF THE TRUST

Trilogy Energy Trust ("Trilogy" or the "Trust") is an open-ended unincorporated investment trust governed by the laws of the Province of Alberta and created pursuant to the Trust Indenture dated February 25, 2005. The Trust is managed by Trilogy Energy Ltd., the administrator of the Trust. The beneficiaries of the Trust are the holders of Trust Units (the "Unitholders").

Pursuant to the plan of arrangement involving Paramount Resources Ltd. ("Paramount") and its shareholders and optionholders as described in the Information Circular of Paramount dated February 28, 2005, the Trust acquired certain properties from Paramount effective April 1, 2005. These assets (the "Trust Assets") are located in the Kaybob and Marten Creek areas of Alberta. Through the plan of arrangement, shareholders of Paramount received, in exchange for each of their common shares, one new common share of Paramount and one unit of the Trust ("Trust Unit"). At closing, shareholders of Paramount owned 81 percent of the issued and outstanding Trust Units with the remaining 19 percent (as at December 31, 2005 – 17.7 percent) of the issued and outstanding Trust Units being held by Paramount.

The transfer of the Trust Assets did not result in a substantial change in ownership of the Trust Assets by Paramount on the effective date of the plan of arrangement and, therefore, the transaction was accounted for at the carrying value of the assets transferred. The carrying values of assets and related liabilities transferred to the Trust on April 1, 2005 were as follows:

Property, plant and equipment – net of accumulated depletion and depreciation	700,129
Asset retirement obligations	(65,076)
Goodwill	19,400
Net working capital accounts	(35,674)
Net carrying value (see note 8)	618,779

The net carrying value of the assets and related liabilities were credited to unitholders' capital account on April 1, 2005. In addition to the issuance of Trust Units described above, the Trust paid Paramount on April 1, 2005 an amount of $190 million in cash plus $30 million as an initial settlement of outstanding working capital distribution amounts in accordance with the plan of arrangement. The $190 million transfer consideration was charged against unitholders' capital account.

The Trust, through a wholly-owned holding trust (Trilogy Holding Trust), indirectly owns the Trust Assets mainly through an operating limited partnership (Trilogy Energy LP). Another wholly owned subsidiary of the Trust, Trilogy Energy Ltd., acts as the general and managing partner of Trilogy Energy LP. As part of the plan of arrangement, the Trust also assumed a $15.0 million debt of, and paid $0.2 million to, a Paramount subsidiary for the transfer of the general partnership interest in Trilogy Energy LP to Trilogy Energy Ltd. This amount was also charged against unitholders' capital on April 1, 2005.

2. BASIS OF PRESENTATION

The consolidated financial statements of the Trust have been prepared in accordance with Canadian generally accepted accounting principles. As mentioned in note 1, the Trust acquired its operating assets from Paramount effective April 1, 2005. These consolidated financial statements present the historic financial position, results of operations and cash flows on a carve-out basis from Paramount as if the Trust had operated as a stand-alone entity subject to Paramount's control prior to April 1, 2005. Commencing April 1, 2005, the Trust holds the Trust Assets, with the earnings from April 1, 2005 being retained until distributed by the Trust.

For the periods up to March 31, 2005, the consolidated financial statements include Paramount's interests in the assets, liabilities, revenues and expenses attributable to the Trust Assets. The costs of petroleum and natural gas properties and other property, plant and equipment, the associated accumulated depletion and depreciation, the liability for asset retirement obligations and the carrying value of goodwill as at December 31, 2004 have been derived directly from the accounting records of Paramount. Other balance sheet accounts that relate to the Trust Assets but could not be derived directly from Paramount's accounting records such as accounts receivable, prepaid expenses, financial instrument assets and liabilities, and accounts payable and accrued liabilities have been allocated on a pro rata basis using production volumes of the Trust Assets as a proportion of the aggregate production volumes of Paramount for the period. Future income taxes on the Trust Assets have been calculated using the liability method.

The amounts of petroleum and natural gas sales, royalties-net of ARTC, operating costs, geological and geophysical costs, dry hole costs, lease rental costs, accretion of asset retirement obligations, write-down of petroleum and natural gas properties, and gain/losses on sale of property and equipment relating to the Trust Assets that are included in the consolidated financial statements for the periods up to March 31, 2005 have been derived directly from the accounting records of Paramount. Paramount's corporate costs such as general and administrative costs and gains and losses from financial instruments relating to petroleum and natural gas price and exchange rate contracts have been allocated for each period on a pro rata basis using production volumes of the Trust Assets as a proportion of the aggregate production volumes of Paramount for the respective periods. Gains and losses from financial instruments relating to interest rate swaps have been allocated on a pro rata basis using interest expense calculated for the Trust Assets as a proportion to interest expense for Paramount for the respective periods. Interest expense is calculated on the deemed debt balance attributable to the Trust Assets, while Large Corporation tax has been allocated using the ratio of Large Corporation tax base relating to the Trust Assets as a proportion of the consolidated Large Corporation tax base of Paramount. Premium on debt exchange and foreign exchange gains and losses were allocated to the Trust Assets using the ratio of deemed foreign currency denominated debt attributable to the Trust assets as a proportion of the foreign currency denominated debt of Paramount.

For purposes of presentation of the consolidated statements of cash flows for the periods prior to April 1, 2005, cash receipts and disbursements are deemed to be transferred to and from Paramount's corporate account concurrent with the respective inflow or outflow of cash and are presented as "Net investment by Paramount Resources Ltd."

As a result of the basis of presentation described above, these financial statements may not be indicative of the results that would have been attained if the Trust had operated as a stand-alone entity for the periods prior to April 1, 2005.

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

CONSOLIDATION

These consolidated financial statements include the accounts of the Trust and its wholly-owned subsidiaries, Trilogy Holding Trust, Trilogy Energy LP and Trilogy Energy Ltd. The Trust obtains all of the economic benefits of the operations of Trilogy Energy LP.

PROPERTY, PLANT AND EQUIPMENT

The Trust follows the successful efforts method of accounting for petroleum and natural gas operations. Under this method, only those costs that result directly in the discovery of petroleum and natural gas reserves are capitalized. Exploration expenses, including geological and geophysical costs, lease rentals and exploratory dry hole costs, are charged to earnings as incurred. Leasehold acquisition costs, including costs of drilling and equipping successful wells, are capitalized. The net costs of unproductive wells, abandoned wells and surrendered leases are charged to earnings in the year of abandonment or surrender. Gains or losses are recognized on the disposition of property, plant and equipment.

Other property, plant and equipment are recorded at cost.

The net amount at which petroleum and natural gas costs on a property or project are carried is subject to a cost recovery test annually or as economic events dictate. An impairment loss is recognized when the carrying amount of the asset is less than the sum of the expected cash flows on an undiscounted basis. The amount of the impairment loss is then calculated as the difference between the carrying amount and the fair value of the asset. Fair value is calculated as the present value of estimated future cash flows.

DEPLETION AND DEPRECIATION

Capitalized costs of proved oil and gas properties are depleted using the unit-of-production method. Depreciation of production equipment, gas plants and gathering systems is calculated using the straight-line method over their estimated useful life of 12 years. Depreciation of other property, plant and equipment is provided on a straight-line basis over the assets' estimated useful lives varying from three to five years.

JOINT OPERATIONS

Certain exploration, development and production activities are conducted jointly with others. These financial statements reflect only the Trust's proportionate interest in such activities.

ASSET RETIREMENT OBLIGATIONS

The fair value of an asset retirement obligation is recognized in the period in which it is incurred or when a reasonable estimate of the fair value can be made. The asset retirement costs equal to the fair value of the retirement obligations are capitalized as part of the cost of the related long-lived asset and allocated to expense on a basis consistent with depreciation and depletion. The liability associated with the asset retirement costs is subsequently adjusted for the passage of time which is recognized as accretion expense in the statement of earnings. The liability is also adjusted due to revisions in either the timing or the amount of the original estimated cash flows associated with the liability. Actual costs incurred upon settlement of the asset retirement obligations will reduce the asset retirement liability to the extent of the liability recorded. Differences between the actual costs incurred upon settlement of the asset retirement obligations and the liability recorded are recognized in earnings in the period in which the settlement occurs.

GOODWILL

Goodwill, which represents the excess of purchase price over the fair value of net assets acquired, is not amortized and is assessed for impairment at least annually. Impairment is assessed based on a comparison of the fair value of the net assets acquired to the carrying value of the net assets, including goodwill. Any excess of the carrying value of goodwill over and above its fair value is the impairment amount, and is charged to earnings in the period the impairment is identified.

IN-SUBSTANCE DEFEASANCE TRUST

Transfers of financial assets to a trust for the purpose of satisfying liabilities when they mature, without the obligation of the Trust being discharged at the time of the transfer, are recognized as repayments of such liabilities in the financial statements.

REVENUE RECOGNITION

Revenues associated with the sale of natural gas, crude oil, and natural gas liquids ("NGLs") are recognized when title passes to the customer. Revenues from oil and natural gas production from properties in which there is an interest with other producers are recognized on a net working interest basis.

FINANCIAL INSTRUMENTS

Derivative financial instrument contracts such as forwards are periodically utilized to manage exposure to fluctuations in petroleum and natural gas prices. Emerging Issues Committee Abstract 128, "Accounting for Trading, Speculative or Non-Hedging Derivative Financial Instruments" ("EIC 128") establishes accounting and reporting standards that require every derivative instrument that does not qualify for hedge accounting to be recorded in the balance sheet as either an asset or liability measured at fair value. Accounting Guideline 13, Hedging Relationships ("AcG 13") establishes the need for companies to formally designate, document and assess the effectiveness of relationships that receive hedge accounting treatment.

Derivative financial instruments in which management has formally documented its risk objectives and strategies for undertaking the hedged transaction are accounted for as hedges. For these instruments, it is determined that the derivative financial instruments are effective as hedges, both at inception and over the term of the hedging relationship, as the term to maturity, the notional amount, the commodity price, exchange rate, and interest rate basis of the instruments, all match the terms of the transaction being hedged. The assessment of the effectiveness of the hedging relationships is performed on an ongoing basis to ensure that the derivatives entered into are highly effective in offsetting changes in fair values or cash flows of the hedged items. The fair values of derivative financial instruments designated as hedges are not reflected in the financial statements. Derivative financial instruments not formally designated as hedges are measured at fair value and recognized on the balance sheet with changes in the fair value recognized in earnings during the period. As at December 31, 2005, the Trust has not designated any of its financial instruments as a hedge (note 11).

INCOME TAXES

The Trust and its subsidiaries are taxable entities under the Income Tax Act (Canada) but are taxable only on income that is not distributed or distributable to the Unitholders. As the Trust has distributed all of its taxable income to the Unitholders pursuant to its Trust Indenture and meets the requirements of the Income Tax Act (Canada) applicable to the Trust, no provision for income tax has been made in these consolidated financial statements since the transfer of the Trust Assets to the Trust.

UNIT-BASED COMPENSATION

The Trust has a unit appreciation plan for certain directors, officers and employees as described in note 10. The Trust measures compensation cost under the unit appreciation plan as the amount by which the quoted market value of Trust Units covered by the grants exceeds the exercise price adjusted by unit distributions. Compensation cost under the proposed unit appreciation plan is accrued over the appreciation units' vesting period. The recorded liability is revalued at the end of each reporting period to reflect changes in the market price of the Trust Unit with the net change recognized in earnings. When appreciation rights are exercised, the accrued liability is reduced. The accrued compensation for a right that is forfeited or cancelled is adjusted by decreasing compensation cost in the period of forfeiture or cancellation.

Non-reciprocal awards of stock options to Trust employees made by a significant unitholder are fair valued using the Black Scholes model and are amortized to compensation expense over their contractual life of two to four years, with a credit to contributed surplus.

PER TRUST UNIT INFORMATION

Per Trust Unit amounts for all periods prior to April 1, 2005 have been presented on a pro-forma basis as if the Trust Units outstanding at April 1, 2005 were all outstanding for each period shown. Basic earnings per Unit were calculated using the weighted average number of Trust Units (79,177,031 Trust Units) outstanding for the nine months ended December 31, 2005. The Trust uses the treasury stock method whereby only "in the money" dilutive instruments impact the diluted calculations. There were no dilutive instruments outstanding for the nine months ended December 31, 2005.

MEASUREMENT UNCERTAINTY

The timely preparation of these consolidated financial statements in conformity with Canadian generally accepted accounting principles requires that management make estimates and assumptions and use judgment that affect the reported amounts of assets and liabilities and the reported amounts of revenues and expenses during the reported periods. Such estimates primarily relate to unsettled transactions and events as of the date of the consolidated financial statement. Actual results could materially differ from these estimates.

The amounts recorded for depletion and depreciation and impairment of petroleum and natural gas properties and equipment, and for asset retirement obligations and related accretion are based on estimates of reserves, future costs, petroleum and natural gas prices and other relevant assumptions. By their nature, these estimates and those related to the discounted cash flow used to assess impairment are subject to measurement uncertainty, and the impact on the financial statements of future periods could be material.

4. PARAMOUNT ACQUISITIONS RELATED TO THE TRUST ASSETS

$185 Million Asset Acquisition

On June 30, 2004, Paramount completed an agreement to acquire oil and natural gas assets for cash consideration of $185.1 million, after adjustments. The assets acquired by Paramount are located in the Kaybob area in central Alberta, in the Fort Liard area in the Northwest Territories and in northeast British Columbia. From the properties acquired, only certain Kaybob area assets are included as part of the Trust Assets. The financial statements reflect the income for only the properties that were transferred to the Trust for the period after the closing date of the acquisition.

The acquisition was accounted for using the purchase method. The following table summarizes the estimated fair value of the net assets acquired:

Property, plant and equipment	211,947
Asset retirement obligations	(26,847)
	185,100

The Trust Assets' portion of the above properties acquired is $91.7 million ($90.2 million before adjustments) of the $185.1 million. Asset retirement obligation for these properties is $22.1 million.

$87 Million Asset Acquisition

On August 16, 2004, Paramount completed the acquisition of assets in the Marten Creek area in Grande Prairie for cash consideration of $86.9 million, after adjustments. The following table summarizes the estimated fair value of the net assets acquired:

Property, plant and equipment	89,015
Asset retirement obligations	(2,115)
	86,900

All of these properties were transferred as part of the Trust Assets and the income for the period after the closing date of this acquisition is included in these financial statements.

5. PROPERTY, PLANT AND EQUIPMENT

	2005			2004		
	Cost	**Accumulated Depletion and Depreciation**	**Net Book Value**	Cost	Accumulated Depletion and Depreciation	Net Book Value
Petroleum and natural gas properties	1,125,973	(454,964)	671,009	1,011,217	(332,997)	678,220
Other	1,423	(208)	1,215	6,428	(4,003)	2,425
	1,127,396	(455,172)	672,224	1,017,645	(337,000)	680,645

Capital costs associated with non-producing petroleum and natural gas properties totaling approximately $72.1 million as at December 31, 2005 ($55.2 million as at December 31, 2004) are not subject to depletion.

6. ASSET RETIREMENT OBLIGATIONS

The following table presents the reconciliation of the beginning and ending aggregate carrying amount of the obligations associated with the retirement of the Trust's oil and gas properties.

	2005	2004
Asset retirement obligations, beginning of year	**63,674**	28,993
Liabilities incurred	**2,085**	30,260
Revisions in estimate	**(26,648)**	—
Liabilities settled	**(1,367)**	—
Accretion expense	**4,962**	4,421
Asset retirement obligations, end of year	**42,706**	63,674

The undiscounted asset retirement obligations at December 31, 2005 is estimated to be $189.1 million (2004 - $82.2 million). The Trust's credit-adjusted risk-free rate is 7.875% (2004 - 7.875%). These obligations will be settled based on the expected life of the underlying assets, the majority of which are not expected to be paid for several years, or decades, in the future and will be funded from the general resources of the Trust at the time of removal.

The Trust updated the estimate of its asset retirement obligation on October 1, 2005 and made a downward revision of the asset retirement obligation by $26.6 million due mainly to the changes in the timing of the expected abandonment partially offset by upward changes in estimated cost of abandonment. This amount reduced the related cost of the underlying assets.

7. LONG-TERM DEBT

On April 1, 2005, the Trust entered into a credit agreement with a syndicate of Canadian chartered banks. Under such credit facility, the Trust has a $265 million committed revolving and term facility and a $35 million working capital facility at year end. Borrowing under the facility bears interest at the lenders' prime rate, Bankers' Acceptance rate or LIBOR, plus an applicable margin dependent on certain conditions. The revolving feature of the Trust's credit facility expires on March 31, 2006 if not extended. Pursuant to the terms of the credit agreement, the Trust has requested an extension of one year. The Trust anticipates the request will be approved and the revolving phase on the credit facility will be extended to

March 30, 2007. Upon the expiry of the credit agreement's revolving phase, amounts outstanding will have a term maturity date of one additional year.

Advances drawn on the Trust's facility are secured by a fixed and floating charge over the assets of the Trust. The amount drawn down from the credit facilities totaled $108.4 million as at December 31, 2005, net of a $50 million deposit-in-trust account used to repay maturing draw downs on January 9, 2006. The weighted average interest rate under this facility for the nine months ended December 31, 2005 was 3.72%.

The Trust has letters of credit totaling $9.6 million as at December 31, 2005 outstanding with a Canadian chartered bank. These letters of credit reduce the amount available under the Trust's working capital facility.

8. UNITHOLDERS' CAPITAL

AUTHORIZED

The authorized capital of the Trust is comprised of an unlimited number of Trust Units and an unlimited number of Special Voting Rights. Compared to the holders of the Trust Units, holders of Special Voting Rights are not entitled to any distributions of any nature from the Trust nor have any beneficial interest in any property or assets of the Trust on termination or winding-up of the Trust.

ISSUED AND OUTSTANDING

No Special Voting Rights have been issued to date. The following is a summary of the changes in the Trust's unitholders' capital for the year ended December 31, 2005:

Trust Units	Number of Units	Amount
Balance at December 31, 2004	—	—
Initial Trust Unit issued upon settlement on February 25, 2005	1	1
Repurchase of initial Trust Unit	(1)	(1)
Trust Units issued to Paramount shareholders in exchange of the Trust Assets (note 1)	79,133,395	618,779
Cash paid for the transfer of the Trust Assets (note 1)	—	(190,000)
Purchase price of the general partnership (1%) interest in Trilogy Energy LP (note 1)	—	(15,211)
Trust Units issuance costs	—	(4,000)
Balance after the transfer of Trust Assets to the Trust	79,133,395	409,568
Trust Units issued, net of issuance costs	6,000,000	140,576
Balance at December 31, 2005	85,133,395	550,144

REDEMPTION RIGHT

Unitholders may redeem their Trust Units at any time by delivering their Trust Units Certificates to the Transfer Agent together with a duly completed and properly executed notice. The redemption price per Trust Unit is equal to the lesser of 90 percent of the market price of the Trust Units on the principal market on which the Trust Units are quoted for trading during the 10 trading day period commencing immediately after the date on which the Trust Units were tendered for redemption, and the closing market price on the principal market on which the Trust Units are quoted for trading on the date that the Trust Units were tendered for redemption. Cash payments for Units tendered for redemption are limited to $50,000 per month with redemption requests in excess of this amount eligible to receive notes from the holding trust or other assets held by the Trust. In addition, cash redemption may not apply if the outstanding Trust Units tendered for redemption are not listed for trading, the normal trading of the Trust Units is suspended or halted on any stock exchange or the redemption of Trust Units will result in the delisting of the Trust Units. In such cases, the fair market value of the Trust Units shall be determined by the Administrator and be paid and satisfied by way of asset distribution.

9. DISTRIBUTIONS

The Trust recorded the following cash distributions to unitholders from April to December 31, 2005:

Nature of Distribution	Record Date	Distribution Date	Distribution per Trust Unit	Amount
Monthly distributions:				
April 2005	May 2, 2005	May 16, 2005	$0.16	12,661
May 2005	May 31, 2005	June 15, 2005	$0.16	12,661
June 2005	June 30, 2005	July 15, 2005	$0.16	12,661
July 2005	August 2, 2005	August 15, 2005	$0.16	12,661
August 2005	August 31, 2005	September 15, 2005	$0.16	12,662
September 2005	September 30, 2005	October 15, 2005	$0.25	19,783
October 2005	October 31, 2005	November 15, 2005	$0.25	19,783
November 2005	November 30, 2005	December 15, 2005	$0.25	19,784
December 2005	December 31, 2005	January 16, 2006	$0.25	21,283
Special distribution:				
December 2005	December 31, 2005	January 16, 2006	$0.55	46,824
Total				190,763

10. UNIT BASED COMPENSATION

UNIT APPRECIATION PLAN

On April 1, 2005, the Trust offered certain employees, officers and directors a unit appreciation arrangement whereby certain employees, officers and directors are granted appreciation units entitling the appreciation unitholders to receive cash payments calculated as the excess of the market price over the exercise price per appreciation unit on the exercise date. The exercise price per appreciation unit shall be reduced by the aggregate unit distributions paid or payable on the Trust Units to unitholders of record from the grant date to the exercise date.

For the period from April 1, 2005 to December 31, 2005, a total of 1,319,000 appreciation units have been granted to certain employees, officers and directors with an exercise price of $10.11 per appreciation unit (before unit distributions adjustment). The appreciation units vest at subsequent anniversary dates with a termination date of December 15, 2008. A continuity of the unit appreciation rights for the nine months ended December 31, 2005 is as follows:

	Exercise Price	No. of Unit Rights
Balance at April 1, 2005	—	—
Granted	$ 10.11	1,319,000
Exercised	$ 8.81	(13,000)
Balance at December 31, 2005	$ 7.76	1,306,000
Unit rights exercisable at December 31, 2005	$ 7.76	230,000

A compensation expense of $8.9 million relating to the unit appreciation plan has been recognized in earnings for the nine months ended December 31, 2005, consisting of cash paid on exercised unit appreciation rights for $0.2 million and accrued compensation cost for the elapsed vesting period of outstanding unit appreciation rights for $8.7 million.

PROPOSED UNIT OPTION AND BONUS PLAN

Subject to approval by the unitholders and appropriate regulatory authorities, the Trust is contemplating implementing a long-term incentive plan that will award unit options to, and set up a market-based bonus plan for, eligible directors, officers, employees and consultants. No compensation expense or liabilities have been recognized by the Trust under this proposed unit option and bonus plan.

11. FINANCIAL INSTRUMENTS

FINANCIAL SALES CONTRACTS

The Trust utilizes, from time to time, forward commodity price contracts that require financial settlements between counterparties. At December 31, 2005, the Trust has entered into financial forward sales arrangements as follows:

	Quantity	Price		Term
Sales Contracts				
AECO Fixed Price	10,000 GJ/d	$ 8.73		November 2005 – March 2006
AECO Fixed Price	10,000 GJ/d	$ 8.71		November 2005 – March 2006
AECO Fixed Price	20,000 GJ/d	$ 8.09		November 2005 – March 2006
AECO Costless Collar	10,000 GJ/d	$ 12.00	Floor	January 2006 – March 2006
		$ 17.65	Ceiling	
AECO Costless Collar	20,000 GJ/d	$ 9.00	Floor	April 2006 – October 2006
		$ 12.50	Ceiling	
AECO Fixed Price	10,000 GJ/d	$ 10.65		April 2006 – October 2006
AECO Fixed Price	10,000 GJ/d	$ 10.75		April 2006 – October 2006
NYMEX-WTI Fixed Price	1,000 Bbl/d	$ 53.43	US	October 2005 – March 2006
Purchase Contract				
AECO Fixed Price	10,000 GJ/d	$ 11.22		February 2006 – March 2006

The Trust elected not to designate the above financial instruments as hedges and therefore has recognized the fair value of these financial instruments on the balance sheet. The estimated fair values of these financial instruments are based on quoted prices or, in their absence, third-party market indications and forecasts. The fair values of forward financial contracts recognized as at the balance sheet dates are as follows:

	2005	2004
Financial instrument asset	**5 ,830**	12,413
Financial instrument liability	**(9,220)**	(1,260)
Net financial instrument asset (liability)	**(3,390)**	11,153

The changes in the fair value associated with the above financial instruments are recorded as unrealized gain or loss on financial instruments in the statement of earnings. Gains or losses arising from monthly settlement with counterparties are recognized as realized gain or loss in the statement of earnings.

CREDIT AND INTEREST RATE RISKS

Under a service agreement described in note 12, Paramount carries out marketing functions on behalf of the Trust. The Trust is exposed to credit risk from financial instruments to the extent of non-performance by third parties. Credit risks associated with possible non-performance by financial instrument counterparties are minimized by entering into contracts with only highly rated counterparties and third party credit risk with credit approvals, limits on exposures to any one counterparty, and monitoring procedures. Production is sold to a variety of purchasers under normal industry sale and payment terms. The Trust's accounts receivable are with customers and joint venture partners in the petroleum and natural gas industry and are subject to normal credit risk.

The Trust is also exposed to fluctuations in interest rates relative to its banks' credit facilities as disclosed in note 7.

12. RELATED PARTY TRANSACTIONS

Paramount is a unitholder of the Trust. On April 1, 2005, Paramount Resources, a wholly-owned subsidiary of Paramount, entered into a service agreement with the Trust's subsidiary and administrator (Trilogy Energy Ltd.) whereby Paramount Resources will provide administrative and operating services to the Trust and its subsidiaries to assist Trilogy Energy Ltd. in carrying out its duties and obligations as general partner of Trilogy Energy LP and as the administrator of the Trust and Trilogy Holding Trust. Under this agreement, Paramount Resources shall be reimbursed at cost for all expenses it incurs in providing the services to the Trust and its subsidiaries. The agreement is in effect until March 31, 2006 but may be terminated by either party with at least six months written notice. The parties are now in the process of extending the term of this agreement until March 31, 2007. The amount of expenses billed by Paramount Resources as management

fees under this agreement was $4.2 million for the nine months ended December 31, 2005. This amount is included as part of the general and administrative expenses in the Trust's consolidated statement of earnings. The Trust had $0.6 million outstanding payable to Paramount at December 31, 2005 arising from this transaction.

Trilogy Energy LP and Paramount entered into a Call on Production Agreement on March 29, 2005 whereby Paramount has the right to purchase all or any portion of Trilogy Energy LP's available gas production at a price no less favorable than the price Paramount will receive on the resale of the natural gas to a gas marketing limited partnership. The Call on Production Agreement was terminated by both parties on November 30, 2005. Trilogy Energy LP sold 8,490,542 GJ of natural gas to Paramount for approximately $70.3 million for the period ended December 31, 2005 under this agreement. The Trust had $1.5 million outstanding receivable from Paramount at December 31, 2005 arising from this transaction.

In addition, the Trust and Paramount also had transactions with each other arising from normal business activities.

The net amount due from Paramount arising from the above related party transactions as at December 31, 2005 was $6.4 million, including a Crown royalty deposit claim of $5.5 million which when refunded to Paramount will be collected by the Trust.

13. COMMITMENTS

The Trust has the following future commitments as at December 31, 2005:

	2006	2007	2008	2009	2010 and after	Total
Pipeline transportation commitments	12,299	9,846	9,846	9,846	50,279	92,116
Office premises operating lease	644	1,374	2,086	1,786	12,205	18,095
Total	12,943	11,220	11,932	11,632	62,484	110,211

Some of the above commitments on pipeline transportation are covered by letters of credit issued by the Trust, as disclosed in note 7.

The Trust also has an outstanding physical contract to sell 10,000 GJ/d of natural gas at an AECO fixed price of $14.04 from January 2006 to March 2006.

14. INCOME TAXES

As disclosed in note 3, no provision for income taxes has been made by the Trust since the transfer of the Trust Assets to the Trust on April 1, 2005. The income taxes prior to April 1, 2005 were calculated on a carve-out basis from Paramount.

15. SUBSEQUENT EVENTS

ACQUISITION

On February 28, 2006, Trilogy entered into an agreement with Redsky Energy Ltd. (Redsky) providing for the acquisition of all of the shares of Redsky for consideration of 6,500,000 Trilogy Trust Units pursuant to a plan of arrangement. Trilogy is expected to assume negligible net debt as a result of this transaction.

The completion of the plan of arrangement is subject to various conditions, including receipt of all required regulatory, shareholder and court approvals. A special meeting of shareholders of Redsky is expected to be called in March 2006.

DISTRIBUTIONS

On February 15, 2006, the Trust paid a cash distribution for January 2006 at $0.25 per Trust Unit. The distribution was paid to unitholders of record on January 31, 2006. Also on February 17, 2006, the Trust announced that its cash distribution for February 2006 will be $0.25 per Trust Unit. The distribution is payable on March 15, 2006 to unitholders of record on February 28, 2006.

The Trust also entered into the following financial contracts subsequent to December 31, 2005:

	Quantity	Price	Term
Sales Contracts			
WTI Fixed Price	1,000 Bbl/d	$ 66.04 US	February 2006 – December 2006
WTI Fixed Price	1,000 Bbl/d	$ 65.64 US	February 2006 – December 2006
WTI Fixed Price	1,000 Bbl/d	$ 68.02 US	February 2006 – December 2006
WTI Fixed Price	1,000 Bbl/d	$ 68.05 US	February 2006 – December 2006
AECO Fixed Price	10,000 GJ/d	$ 7.80	March 2006
AECO Fixed Price	10,000 GJ/d	$ 7.96	April 2006 – October 2006
Purchase Contract			
AECO Fixed Price	10,000 GJ/d	$ 7.27	March 2006

Corporate Information

OFFICERS

J. H. T. Riddell
President and Chief Executive Officer

B. K. Lee
Chief Financial Officer

C. E. Morin
Corporate Secretary

J. B. Williams
Chief Operating Officer

DIRECTORS

C. H. Riddell(1)
Chairman of the Board
Calgary, Alberta

J. H. T. Riddell(4)
President and Chief Executive Officer
Calgary, Alberta

M. H. Dilger(2)(4)
Vice President, Business Development
Pembina Management Inc.
(Administrator of Pembina Pipeline Income Fund)
Calgary, Alberta

R.M. MacDonald(2)(3)
Independent Businessman
Calgary, Alberta

E.M. Shier(3)(4)
Partner, Heenan Blaikie LLP
Calgary, Alberta

D.F. Textor(1)(3)
Portfolio Manager,
Dorset Management Corporation,
Partner, Knott Partners Management LLC
Locust Valley, New York

J.G. Williams(1)(2)
President and Chief Executive Officer
Adeco Exploration Company Ltd.
Calgary, Alberta

Committees of the Board of Directors of Trilogy Energy Ltd.
(Administrator of the Trust)
(1) Member of the Compensation Committee
(2) Member of the Audit Committee
(3) Member of the Corporate Governance Committee
(4) Member of the Environmental, Health & Safety Committee

HEAD OFFICE

4100, 350 7th Avenue SW
Calgary, Alberta
Canada T2P 3N9

Telephone: (403) 290-2900
Facsimile: (403) 263-8915
www.trilogyenergy.com

AUDITORS

PricewaterhouseCoopers LLP
Calgary, Alberta

BANKERS

ATB Financial
Calgary, Alberta
Bank of Montreal
Calgary, Alberta
The Bank of Nova Scotia
Calgary, Alberta
Canadian Imperial Bank of Commerce
Calgary, Alberta
Royal Bank of Canada
Calgary, Alberta

REGISTRAR AND TRANSFER AGENT

Computershare Investor Services Canada
Calgary, Alberta
Toronto, Ontario

STOCK EXCHANGE LISTING

The Toronto Stock Exchange
"TET.UN"

designed and produced by nonfiction studios inc.

TRILOGY
ENERGY TRUST

4100, 350 7th AVENUE SW
CALGARY, ALBERTA
CANADA T2P 3N9

TELEPHONE: (403) 290-2900
FACSIMILE: (403) 263-8915
WWW.TRILOGYENERGY.COM